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Acurex Corp.
Mountain View, CA

Prepared for

Industrial Environmental Research Lab.
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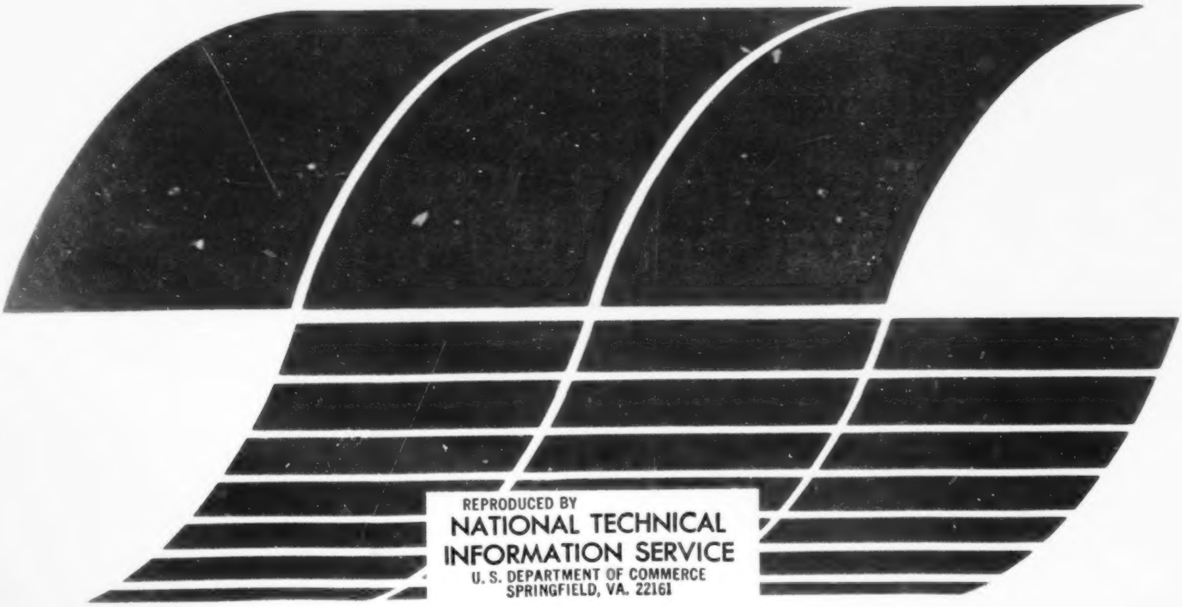

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16. ABSTRACT
The report gives results of an assessment of current and developing combustion modification NOx control technology for coal-, oil-, and natural-gas-fired industrial boilers. Control effectiveness and applicability, reliability and availability, process impacts, capital and operating costs, energy impacts, and environmental impacts are evaluated. Currently available techniques are capable of moderate (10-25%) NOx reductions for coal- and residual-oil-fired boilers and major (40-70%) reductions for distillate-oil- and gas-fired units with minimal adverse operating impacts. Combustion modifications are estimated to increase the cost of steam by only 1-2%, but could increase the initial capital cost of a boiler by 1-20%. Analysis of measured or postulated incremental emissions, other than NOx, indicates that these emissions are generally unaffected when preferred NOx controls are implemented, although further testing is warranted.

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PREFACE

The 1977 Amendments to the Clean Air Act required that emission standards be developed for fossil-fuel-fired steam generators. Accordingly, the U.S. Environmental Protection Agency (EPA) recently promulgated revisions to the 1971 new source performance standard (NSPS) for electric utility steam generating units. Further, EPA has undertaken a study of industrial boilers with the intent of proposing a NSPS for this category of sources. The study is being directed by EPA's Office of Air Quality Planning and Standards, and technical support is being provided by EPA's Office of Research and Development. As part of this support, the Industrial Environmental Research Laboratory at Research Triangle Park, N.C., prepared a series of technology assessment reports to aid in determining the technological basis for the NSPS for industrial boilers. This report is part of that series. The complete report series is listed below:

Title	Report No.
The Population and Characteristics of Industrial/ Commercial Boilers	EPA-600/7-79-178a
Technology Assessment Report for Industrial Boiler Applications: Oil Cleaning	EPA-600/7-79-178b
Technology Assessment Report for Industrial Boiler Applications: Coal Cleaning and Low Sulfur Coal	EPA-600/7-79-178c
Technology Assessment Report for Industrial Boiler Applications: Synthetic Fuels	EPA-600/7-79-178d

Title	Report No.
Technology Assessment Report for Industrial Boiler Applications: Fluidized-Bed Combustion	EPA-600/7-79-178e
Technology Assessment Report for Industrial Boiler Applications: NO_x Combustion Modification	EPA-600/7-79-178f
Technology Assessment Report for Industrial Boiler Applications: NO_x Flue Gas Treatment	EPA-600/7-79-178g
Technology Assessment Report for Industrial Boiler Applications: Particulate Collection	EPA-600/7-79-178h
Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization	EPA-600/7-79-178i

These reports will be integrated along with other information in the document, "Industrial Boilers -- Background Information for Proposed Standards," which will be issued by the Office of Air Quality Planning and Standards.

TABLE OF CONTENTS

Section Page

Acknowledgment ii
Preface. iii

1 EXECUTIVE SUMMARY 1-1

1.1 Introduction 1-1
1.2 NO_x Formation Mechanisms and Principles of Control 1-2
1.3 Systems of NO_x Emissions Reduction for Coal-Fired Boilers 1-5

1.3.1 Candidate Best Systems of Control for Coal-Fired Boilers 1-5
1.3.2 Best Systems of Control for Coal-Fired Boilers 110

1.4 Systems of NO_x Emission Reduction for Oil-Fired Boilers 1-15

1.4.1 Candidate Best Systems of Control for Oil-Fired Boilers 1-15
1.4.2 Best Systems of Control for Oil-Fired Boilers 1-18

1.5 Systems of NO_x Emission Reduction for Gas-Fired Boilers 1-21
1.6 Energy Impact 1-22
1.7 Cost Impact 1-22
1.8 Environmental Impact 1-24

2 EMISSIONS CONTROL TECHNIQUES 2-1

2.1 NO_x Formation Mechanism and Principles of Control 2-2

2.1.1 Thermal NO_x 2-2
2.1.2 Fuel NO_x 2-4
2.1.3 Principles of Control 2-9

2.2 Coal-Fired Boilers 2-10

2.2.1 Applicable Control Techniques for Pulverized Coal-Fired Boilers 2-14
2.2.2 Applicable Control Techniques for Stokers . . . 2-26

TABLE OF CONTENTS (Continued)

Section Page

2.3 Oil-Fired Boilers 2-31

2.3.1 Low Excess Air (LEA) 2-36
2.3.2 Staged Combustion 2-37
2.3.3 Flue Gas Recirculation (FGR) 2-43
2.3.4 Combined Flue Gas Recirculation and Staged Combustion 2-47
2.3.5 Reduced Air Preheat (RAP) 3-47
2.3.6 Load Reduction 2-48
2.3.7 Low NO_x Burners (LNB) 2-49
2.3.8 Ammonia Injection 2-60

2.4 Gas-Fired Boilers 2-63

2.4.1 Low Excess Air (LEA) 2-63
2.4.2 Staged Combustion Air (SCA) 2-67
2.4.3 Flue Gas Recirculation (FGR) 2-69
2.4.4 Combined Flue Gas Recirculation and Staged Combustion 2-71
2.4.5 Load Reduction 2-71
2.4.6 Reduced Air Preheat (RAP) 2-72
2.4.7 Low NO_x Burners (LNB) 2-72
2.4.8 Ammonia Injection 2-73

3 CANDIDATES FOR BEST SYSTEMS OF EMISSION REDUCTION . . . 3-1

3.1 Criteria for Selection 3-1
3.2 Candidate Control Systems for Coal-Fired Industrial Boilers 3-12

3.2.1 Pulverized Coal-Fired Boilers 3-15
3.2.2 Spreader Stoker Boilers 3-17
3.2.3 Chain Grate and Underfeed Stokers 3-19

3.3 Candidate Best Control Systems for Residual Oil-Fired Industrial Boilers 3-19

3.3.1 Firetube Boilers 3-20
3.3.2 Watertube Boilers 3-22
3.3.3 Effects of Fuel Nitrogen 3-25

3.4 Candidate Best Control Systems for Distillate Oil-Fired Industrial Boilers 3-26

3.4.1 Firetube Boilers 3-29
3.4.2 Watertube Boilers Without Air Preheaters 3-30
3.4.3 Watertube Boilers Equipped with Preheaters . . . 3-32

TABLE OF CONTENTS (Continued)

Section Page

3.5 Candidate Best Control System for Natural Gas-Fired Industrial Boilers 3-33

3.5.1 Firetube Boilers 3-34
3.5.2 Watertube Boilers Without an Air Preheater . . . 3-34
3.5.3 Watertube Boilers with Air Preheater 3-36

3.6 Summary 3-38

4 COST IMPACT 4-1

4.1 Cost Analysis 4-1

4.1.1 Components of Control Costs 4-1
4.1.2 Cost Basis 4-3

4.2 Control Costs for Coal-Fired Boilers 4-7

4.2.1 New Facilities 4-19
4.2.2 Modified and Reconstructed Facilities 4-20

4.3 Control Costs for Oil-Fired Boilers 4-20

4.3.1 New Facilities 4-41
4.3.2 Modified and Reconstructed Facilities 4-42

4.4 Control Costs for Natural Gas-Fired Boilers . . . 4-43

4.4.1 New Facilities 4-43
4.4.2 Modifed and Reconstructed Facilities 4-43

4.5 Summary 4-55

5 ENERGY IMPACT 5-1

5.1 Introduction 5-1
5.2 Energy Impact of Controls for Coal-Fired Boilers 5-4

5.2.1 New Facilities 5-4
5.2.2 Modified and Reconstructed Facilities 5-8

5.3 Energy Impact of Controls for Oil-Fired Boilers 5-9

TABLE OF CONTENTS (Concluded)

Section | Page

5.3.1 New Units 5-9
5.3.2 Retrofitted Facilities 5-17

5.4 Energy Impact of Controls for Gas-Fired Boilers 5-17

5.4.1 New Facilities 5-17
5.4.2 Retrofitted Facilities 5-22

5.5 Summary 5-22

6 ENVIRONMENTAL IMPACTS OF CANDIDATES FOR BEST EMISSION CONTROL SYSTEMS 6-1

6.1 Identification of the Major Environmental Concerns 6-1
6.2 Formation Mechanisms of Major Pollutants 6-4

6.2.1 Criteria Pollutants -- Formation Mechanisms . . 6-5
6.2.2 Noncriteria Pollutants -- Formation Mechanisms 6-8

6.3 Environmental Impacts of NO_x Controls for Coal-Fired Boilers 6-11
6.4 Environmental Impacts of NO_x Controls for Residual Oil-Fired Boilers 6-24
6.5 Environmental Impacts of NO_x Controls for Distillate Oil and Natural Gas-Fired Boilers . . . 6-48
6.6 Other Pollution Sources 6-64
6.7 Summary 6-68

7 EMISSION SOURCE TEST DATA 7-1

7.1 Criteria for Selection 7-1

7.1.1 Data Selection 7-1
7.1.2 Test Methods 7-2

7.2 Emission Source Test Data for Coal-Fired Boilers 7-5
7.3 Emission Source Test Data for Oil-Fired Industrial Boilers 7-5
7.4 Emission Source Test Data for Gas-Fired Boilers 7-24
7.5 Developing Emission Source Test Data 7-24

APPENDIX A -- COST DETAILS A-1
APPENDIX B -- LIST OF COMMON ABREVIATIONS B-1

LIST OF ILLUSTRATIONS

Figure		Page
1-1	Estimated Annualized Control Cost versus NO_x Level for Coal-Fired Boilers	1-25
1-2	Estimated annualized Control Cost versus NO_x Emission Level for Residual Oil-Fired Boilers	1-26
1-3	Estimated Annualized Control Cost versus NO_x Emission Levels for Distillate Oil and Natural Gas-Fired 4.4 MW Firetube Boilers	1-27
2-1	Nitrogen and Sulfur Content of U.S. Coal Reserves	2-6
2-2	Nitric Oxide Emission as Measured vs. Coal Nitrogen Content	2-7
2-3	Distributed Fuel/Air Mixing Concept	2-21
2-4	Typical Fuel Gas Recirculation System for NO_x Control	2-22
2-5	Schematic Diagram of the NH_3 Injection System	2-24
2-6	Air Injection in a Traveling-Grade Spreader Stoker	2-29
2-7	Schematic of Staged Combustion Air Injection for an Oil- and Gas-Fired Firetube Boiler	2-38
2-8	Schematic of Staged Air System Installed for Single Burner Packaged Watertube Oil-Fired Boilers	2-40
2-9	Schematic of Stage Air System Installed on "D" Type Packaged Watertube Boiler	2-41
2-10	Layout of Flue Gas Recirculation System for a Firetube Boiler	2-44
2-11	Layout of Flue Gas Recirculation System for a Packaged Watertube Boiler	2-45
2-12	Alternate Layout of Flue Gas Recirculation System for a Packaged Watertube Boiler	2-46
2-13	The Nippon/TRW Burner	2-52
2-14	Performance Results of the Nippon/TRW Low NO_x Burner	2-53

LIST OF ILLUSTRATIONS (Continued)

Figure		Page
2-15	Ishikawajima-Harima Divided Flame Burner	2-55
2-16	Effect of Flame Division on NO_x and Dust Concentrations (Ishikawajima-Harima Burner)	2-55
2-17.	Effect of Combined Combustion Modifications NO_x Control of the Performance of the Ishikawajima-Harima Low NO_x Burner	2-57
2-18	Schematic of Tokoyo Gas Company Two-Stage Combustion Type Burner for Low NO_x Formation	2-58
2-19	Kawasaki Two-Stage Combustion-Type Burner for Oil . . .	2-58
2-20	Effect of Kawasaki Low NO_x Burner on NO_x Emissions	2-59
2-21	Ammonia Injection System Performance on Commerical Units as Functions of Temperatures	2-61
2-22	Schematic of Ammonia Injection System on a Firetube Boiler	2-62
2-23	Schematic of the Windbox Burner Arrangement of a Firetube Burner	2-70
2-24	Schematic of Register Burner Installed in a Watertube Boiler	2-71
3-1	Effect of Fuel Nitrogen Content on NO_x Emissions from Residual Oil-Fired Industrial Boilers	3-27
4-1	Estimated Annualized Control Cost versus NO_x Level for Coal-Fired Boilers	4-8
4-2	Estimated Annualized Control Cost versus NO_x Emission Level for Residual Oil-Fired Boilers	4-9
4-3	Estimated Annualized Control Cost Versus NO_x Emission Levels for Distillate Oil and Natural Gas-Fired 4.4 MW Firetube Boiler	4-10
6-1	Change in Incremental Emissions from Coal-Fired Industrial Boilers $\geq$29 MW	6-20
6-2	Change in Incremental Emissions from Coal-Fired Industrial Boilers <29 MW	6-21

LIST OF ILLUSTRATIONS (Continued)

Figure		Page
6-3	Partitioning of Elements Based on Effluent Location for a Coal-Fired Industrial Boiler	6-23
6-4	Trace Element Concentration in Fine Particulate	6-25
6-5	Change in Incremental Emissions with Low Excess NO_x Control for Residual Oil-Fired Watertube Industrial Boilers	6-32
6-6	Changes in CO and NO_x Emission with Reduced Excess Oxygen for a Residual Oil-Fired Watertube Industrial Boiler	6-33
6-7	Change in Incremental Emissions with Overfire Air NO_x Control for Residual Oil-Fired Watertube Industrial Boilers	6-34
6-8	Change in CO and NO_x Emissions with Decreasing Excess Oxygen for a Residual Oil-Fired Firetube Industrial Boiler	6-35
6-9	Effect of Low Excess Air NO_x Control on Particle Size Distribution for a Residual Oil-Fired Watertube Industrial Boiler	6-39
6-10	Effect of NO_x Controls on Particle Size Distribution for a Residual Oil-Fired Watertube Industrial Boiler	6-40
6-11	Effect of NO_x Controls on Particle Size Distribution for a Residual Oil-Fired Watertube Industrial Boiler	6-41
6-12	Change in CO Emission Rate with NO_x Control for Distillate Oil-Fired Industrial Boiler	6-60
6-13	Change in UHC Emission Rate with NO_x Control for Distillate Oil-Fired Industrial Boiler	6-61
6-14	Change in CO Emissions with NO_x Control for a Gas-Fired Industrial Boiler	6-62
6-15	Changes in CO and NO_x Emissions with Reduced Excess Oxygen for a Gas-Fired Watertube Industrial Boiler	6-63

LIST OF ILLUSTRATIONS (Concluded)

Figure		Page
6-16	Change in Unburned Hydrocarbon Emissions with NO_x Control for Gas-Fired Industrial Boilers	6-65
6-17	Change in Particulate Emissions with NO_x Control for a Distillate Oil-Fired Watertube Industrial Boiler	6-66

LIST OF TABLES

Table Page

1-1 Major Industrial Boiler/Fuel Categories and Baseline NO_x Emission Levels 1-3

1-2 Summary of Combustion Process Modification Concepts . . 1-4

1-3 Candidates for Best Systems of NO_x Emissions Reduction: Pulverized Coal-Fired Boilers 1-8

1-4 Candidates for Best Systems of NO_x Emissions Reduction: Stoker Coal-Fired Boilers 1-9

1-5 Best Control Systems for Coal-Fired Industrial Boilers with Heat Input $\leq$ 29 MW 1-11

1-6 Best Control Systems for Coal-Fired Industrial Boilers with Heat Input >29 MW 1-12

1-7 Candidates for Best System of NO_x Emissions Reduction: Residual Oil-Fired Boilers 1-16

1-8 Candidates for Best Systems of NO_x Emissions Reduction: Distillate Oil- and Gas-Fired Boilers . . . 1-17

1-9 Best Control System for Residual Oil-Fired Industrial Boilers 1-19

1-10 Best Control Systems for Distillate Oil-Fired Industrial Boilers 1-20

1-11 Best Control Systems for Natural Gas-Fired Industrial Boilers 1-23

1-12 Postulated Effect of Candidate NO_x Control Systems on Incremental Emissions from Coal-Fired Industrial Boilers 1-29

1-13 Postulated Effect of Candidate NO_x Control Systems on Incremental Emissions from Residual Oil-Fired Industrial Boilers 1-30

1-14 Postulated Effect of Candidate NO_x Control Systems on Incremental Emissions from Distillate Oil-Fired Industrial Boilers 1-31

1-15 Postulated Effect of Candidate NO_x Control Systems on Incremental Emissions from Gas-Fired Industrial Boilers 1-32

LIST OF TABLES (Continued)

Table		Page
2-1	Summary of Combustion Process Modification Concepts	2-11
2-2	Applicability of Combustion Modification NO_x Controls for Major Industrial Boiler Equipment/Fuel Types	2-12
2-3	Combustion Modification NO_x Controls for Pulverized Coal-Fired Industrial Boilers	2-15
2-4	Combustion Modification NO_x Controls for Stoker Coal-Fired Industrial Boilers	2-28
2-5	NO_x Emissions at Baseline and Low Excess Air from Oil-Fired Industrial Boilers	2-33
2-6	Combustion Modification NO_x Controls for Oil-Fired Industrial Boilers	2-34
2-7	Low NO_x Burners for Oil and Gas Firing	2-51
2-8	Baseline NO_x Emission from Natural Gas-Fired Industrial Boilers	2-64
2-9	Combustion Modification NO_x Controls for Gas-Fired Industrial Boilers	2-65
3-1	Comparison of Baseline NO_x Emission Levels	3-4
3-2	Candidates for Best Systems of NO_x Emissions Reduction: Pulverized Coal-Fired Boilers	3-6
3-3	Candidates for Best Systems of NO_x Emissions Reduction: Stoker Coal-Fired Boilers	3-7
3-4	Candidates for Best Systems for NO_x Emissions Reduction: Residual Oil-Fired Boilers	3-8
3-5	Candidates for Best Systems of NO_x Emissions Reduction: Distillate Oil- and Gas-Fired Boilers . . .	3-9
3-6	Suggested NO_x Control Levels for Industrial Boilers	3-11
3-7	Best Control Systems for Coal-Fired Industrial Boilers with Heat Input >29 MW	3-13

LIST OF TABLES (Continued)

Table		Page
3-8	Best Control Systems for Coal-Fired Industrial Boilers with Heat Input <29 MW	3-14
3-9	Best Control System for Residual Oil-Fired Industrial Boilers	3-21
3-10	Best Control Systems for Distillate Oil-Fired Industrial Boilers	3-28
3-11	Best Control Systems for Natural Gas-Fired Industrial Boilers	3-35
4-1	Cost Basis for Evaluating NO_x Controls	4-4
4-2	Estimated Costs of Candidate NO_x Control Techniques for New Coal-Fired Boilers	4-11
4-3	Estimated Cost-Effectiveness and Impact of Candidate NO_x Control Techniques for New Coal-Fired Boilers . . .	4-13
4-4	Estimated Costs of Candidate Control Techniques for Retrofitted Coal-Fired Boilers	4-15
4-5	Estimated Cost-Effectiveness and Impacts of Candidate NO_x Control Techniques for Retrofitted Coal-Fired Boilers	4-17
4-6	Estimated Costs of Candidate NO_x Control Techniques for New Residual Oil-Fired Boilers	4-21
4-7	Estimated Cost-Effectiveness and Impacts of Candidate NO_x Control Techniques for New Residual Oil-Fired Boilers	4-23
4-8	Estimated Costs of Candidate NO_x Control Techniques for New Distillate Oil-Fired Boilers	4-25
4-9	Estimated Cost-Effectiveness and Impacts of Candidate NO_x Control Techniques for New Distillate Oil-Fired Boilers	4-28
4-10	Estimated Costs of Candidate NO_x Control Techniques for Retrofitted Residual Oil-Fired Boilers	4-31
4-11	Estimated Cost Effectiveness and Impacts of Candidate NO_x Control Techniques for Retrofitted Residual Oil-Fired Boilers	4-33

LIST OF TABLES (Continued)

Table | Page

4-12 Estimated Costs of Candidate NO_x Techniques for Retrofitted Distillate Oil-Fired Boilers 4-35

4-13 Estimated Cost Effectiveness and Impacts of Candidate NO_x Control Techniques for Retrofitted Distillate Oil-Fired Boilers 4-38

4-14 Estimated Costs of Candidate NO_x Control Techniques for New Natural Gas-Fired Boilers 4-44

4-15 Estimated Cost Effectiveness and Impacts of Candidate NO_x Control Techniques for New Natural Gas-Fired Boilers 4-46

4-16 Estimated Costs of Candidate NO_x Control Techniques for Retrofitted Natural Gas Boilers 4-49

4-17 Estimated Cost Effectiveness and Impacts of Candidate NO_x Control Techniques for Retrofitted Natural Gas-Fired Boilers 4-52

5-1 Average State Implementation Plan Requirements 5-1

5-2 Energy Consumption Due to NO_x Control Techniques for Coal-Fired Boilers 5-5

5-3 Energy Consumption for NO_x Control Techniques for Residual Oil-Fired Boilers 5-10

5-4 Energy Consumption Due to NO_x Control Techniques for Distillate Oil-Fired Boilers 5-12

5-5 Energy Consumption due to NO_x Control Techniques for Natural Gas-Fired Boilers 5-18

6-1 Postulated Effect of Combustion Modifications on Incremental Emissions from Industrial Boilers 6-2

6-2 Incremental Emissions from Pulverized Coal-Fired Industrial Boilers 6-13

6-3 Incremental Emissions from Stoker Coal-Fired Industrial Boilers 6-15

6-4 Effect of Overfire Air NO_x Control on Particle Size Distribution for a Coal-Fired Chain Grate Stoker 6-22

LIST OF TABLES (Continued)

Table		Page
6-5	Emission Rates of Polycyclic Organic Matter (POM) from a Coal-Fired Chain-Grate Stoker Boiler	6-26
6-6	Incremental Emissions from Residual Oil-Fired Boilers	6-27
6-7	Effect of Overfire Air NO_x Control on Particle Size Distribution for a Residual Oil-Fired Watertube Boiler	6-38
6-8	Effect of Combined Low Excess Air, Staged Combustion, and Flue Gas Recirculation on Polycyclic Organic Matter (POM) Emissions from a Residual Oil-Fired Industrial Boiler	6-42
6-9	Effect of NO_x Control on Polycyclic Organic Matter (POM) Emissions from a Residual Oil-Fired Boiler: XAD-2 Resin Test Only	6-44
6-10	Effect of Combined Low Excess Air, Staged Combustion, and Flue Gas Recirculation on Trace Species Emissions from a Residual Oil-Fired Industrial Boiler	6-45
6-11	Trace Species Emissions from a Residual Oil-Fired Industrial Boiler under Baseline Conditions (Test 2)	6-46
6-12	Trace Species Emission from a Residual Oil-Fired Industrial Boiler under Low NO_x Conditions (Test 3)	6-47
6-13	Incremental Emission from Distillate Oil-Fired Industrial Boilers	6-49
6-14	Incremental Emission for Natural Gas-Fired Industrial Boilers	6-53
6-15	Effect of Overfire Air NO_x Control on Particle Size Distribution for a Distillate Oil-Fired Watertube Industrial Boiler	6-67
6-16	Postulated Effect of Candidate NO_x Control Systems on Incremental Emissions from Coal-Fired Industrial Boilers	6-69

LIST OF TABLES (Continued)

Table		Page
6-17	Postulated Effect of Candidate NO_x Control Systems on Incremental Emissions from Residual Oil-Fired Industrial Boilers	6-70
6-18	Postulated Effect of Candidate NO_x Control Systems on Incremental Emission from Distillate Oil-Fired Industrial Boilers	6-71
6-19	Postulated Effect of Candidate NO_x Control Systems on Incremental Emissions from Gas-Fired Industrial Boilers	6-72
7-1	Emission Measurement Instrumentation	7-4
7-2	NO_x Emission Test Data from Pulverized Coal-Fired Industrial Boilers with Low Excess Air (LEA)	7-6
7-3	NO_x Emission Test Data from Pulverized Coal-Fired Industrial Boilers with Burners Out-Of-Service (BOOS)	7-7
7-4	NO_x Emission Test Data from Pulverized Coal-Fired Indusdrial Boilers with Load Reduction (LR)	7-8
7-5	NO_x Emission Test Data from Coal-Fired Industrial Stokers with Low Excess Air (LEA)	7-9
7-6	NO_x Emission Test Data from Coal-Fired Industrial Stokers with Overfire Air (OFA)	7-11
7-7	NO_x Emission Test Data from Coal-Fired Industrial Stokers with Load Reduction (LR)	7-12
7-8	NO_x Emission Test Data from Coal-Fired Industrial Stokers with Reduced Air Preheat (RAP)	7-14
7-9	NO_x Emission Test Data from Residual Oil-Fired Industrial Boilers with Low Excess Air (LEA)	7-15
7-10	NO_x Emission Test Data from Residual Oil-Fired Industrial Boilers with Staged Combustion Air (SCA) . .	7-17
7-11	NO_x Emission Test Data from Residual Oil-Fired Industrial Boilers with Burners Out of Service (BOOS)	7-18

LIST OF TABLES (Continued)

Table Page

7-12. NO_x Emission Test Data from Residual Oil-Fired Industrial Boilers with Flue Gas Recirculation (FGR) . . 7-19

7-13. NO_x Emission Test Data from Residual Oil-Fired Industrial Boilers with Combined Flue Gas Recirculation and Staged Combustion Air (FGR/SCA) . . . 7-20

7-14. NO_x Emission Test Data from Residual Oil-Fired Industrial Boilers with Reduced Air Preheat (RAP) . . . 7-21

7-15. NO_x Emission Test Data from Residual Oil-Fired Industrial Boilers with Load Reduction (LR) 7-22

7-16. NO_x Emission Test Data from Distillate (No. 2) Oil-Fired Industrial Boilers with Low Excess Air (LEA) 7-25

7-17. NO_x Emission Test Data from Distillate (No. 2) Oil-Fired Industrial Boilers with Flue Gas Recirculation (FGR) 7-26

7-18. NO_x Emission Test Data from Distillate (No. 2) Oil-Fired Industrial Boilers with Staged Combustion Air (SCA) 7-27

7-19. NO_x Test Data from Distillate (No. 2) Oil-Fired Industrial Boilers with Combined Flue Gas Recirculation and Staged Combustion Air (FGR/SCA) . . . 7-28

7-20. NO_x Emission Test Data from Distillate (No. 2) Oil-Fired Industrial Boilers with Load Reduction (LR) 7-29

7-21. NO_x Emission Test Data from Gas-Fired Industrial Boiler with Low Excess Air (LEA) 7-29

7-22. NO_x Emission Test Data from Natural Gas-Fired Industrial Boilers with Staged Combustion Air (SCA) . . 7-33

7-23. NO_x Emission Test Data from Natural Gas-Fired Industrial Boilers with Flue Gas Recirculation (FGR) . . 7-34

7-24. NO_x Test Data from Natural Gas-Fired Industrial Boilers with Combined Flue Gas Recirculation and Staged Combustion (FGR/SCA) 7-35

LIST OF TABLES (Concluded)

Table Page

7-25. NO_x Emission Test Data from Natural Gas-Fired Industrial Boilers with Load Reduction (LR) 7-35

7-26. NO_x Emission Test Data from Natural Gas-Fired Industrial Boilers with Reduced Air Preheat (RAP) . . . 7-37

7-27. NO_x Emission Test Data from Natural Gas-Fired Industrial Boilers with Burners Out of Service (BOOS) 7-38

SECTION 1

EXECUTIVE SUMMARY

Industrial boilers produce more than 20 percent of all stationary combustion source nitrogen oxides (NO_x) emissions.* Combustion modification control techniques represent potentially viable means of controlling NO_x. The objective of this report is to assess combustion modification NO_x control technology in order to supply background information for the EPA Office of Air Quality Planning and Standards in their evaluation of alternative control systems for industrial boilers.

1.1 INTRODUCTION

This report evaluates the effectiveness, applicability, and limitations of specific combustion modification NO_x controls for each major equipment/fuel category in the industrial boiler sector. The current baseline or normal operating level NO_x emission factors for these major boiler/fuel categories are compiled and the effectiveness of combustion modifications in reducing these NO_x emission levels are reviewed. Only limited, short term field test results (though well documented) are available to date, as NO_x controls are not currently widely practiced in the industrial boiler sector. This summary highlights some of the general trends observed after a thorough review of available, well documented, published data. These observations are meant to be only guidelines; there will certainly be exceptions, and much research and development work remains before NO_x control technology is well characterized for all of the diverse industrial boiler design and equipment types. Indeed, EPA's Industrial Environmental Research Laboratory at Research Triangle Park, N.C., is currently expanding the existing data base through a number of control development programs, including 30-day continuous monitoring field tests.

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*Reference 2-10

Industrial boilers are defined here as coal-, oil-, or natural gas-fired steam generators in the industrial sector with heat input capacities greater than 3 MW (10×10^6 Btu/hr). Major equipment/fuel categories for industrial boilers have been identified and are listed in Table 1-1, along with typical heat input capacities and average baseline NO_x emission levels.

1.2 NO_x FORMATION MECHANISMS AND PRINCIPLES OF CONTROL

Oxides of nitrogen (NO_x) formed in combustion processes are usually due either to thermal fixation of atmospheric nitrogen in the combustion air, leading to "thermal NO_x" or to the conversion of chemically bound nitrogen in the fuel, leading to "fuel NO_x." For natural gas and distillate oil firing, nearly all NO_x emissions result from thermal fixation. With residual oil and coal, the contribution from fuel-bound nitrogen can be significant and, under certain operating conditions, predominate.

Both thermal and fuel NO_x appear to be kinetically or aerodynamically limited because emission rates are far below the levels which would prevail at equilibrium. Thus, the rate of formation of both thermal and fuel NO_x is dominated by combustion conditions and is amenable to suppression through combustion process modifications. Although the mechanisms are different, both thermal and fuel NO_x are promoted by rapid mixing of oxygen with the fuel. Additionally, thermal NO_x is greatly increased by long residence time at high temperature. The modified combustion conditions and control concepts which have been tried or suggested to limit NO_x formation are as follows:

- Decrease primary flame zone O_2 level by:
    - -- Decreased overall O_2 level
    - -- Controlled mixing of fuel and air
    - -- Use of fuel-rich primary flame zone
- Decrease time of exposure at high temperature by:
    - -- Decreased peak temperature
    - -- Decreased adiabatic flame temperature through dilution
    - -- Decreased combustion intensity
    - -- Increased flame cooling

TABLE 1-1. MAJOR INDUSTRIAL BOILER/FUEL CATEGORIES AND BASELINE NO_x EMISSION LEVELS

Fuel	Boiler Type	Typical Size (Heat input Capacity) MW(10^6 Btu/hr)	No. of Boilers Tested	Average NO_x Baseline Emission Level ng NO_2/J(lb/10^6 Btu)	AP-42 (Ref. 3-2) NO_x Baseline Emission Level ng NO_2/J(lb/10^6 Btu)	Sources of Data Used for Selected Baseline Emissions
Pulverized Coal	Single Wall and Tangential	59(200) 114(400)	4 2	285(0.663) 285(0.663)	328(0.763) 328(0.763)	Ref. 3-3, 3-4, 3-5 Ref. 3-3, 3-4, 3-5
Stoker Coal	Spreader	44(150), 25(85)	7,5	265(0.616)	273(0.635)	Ref. 3-2 through 3-6
	Underfeed	9(30)	2	150(0.349)	273(0.635)	Ref. 3-3
	Chain Grate	22(75)	2	140(0.326)	273(0.635)	Ref. 3-4, 3-5
Residual Oil[a]	Firetube	4.4(15)	5	115(0.267)	--	Ref. 3-3, 3-4, 3-8
	Watertube	8.8(30)	10	160(0.372)	171(0.398)	Ref. 3-3, 3-4, 3-8, 3-9
	Watertube	44(150)	7	160(0.372)	171(0.398)	Ref. 3-3, 3-4
Distillate Oil	Firetube	4.4(15)	6	75(0.175)	68(0.158)	Ref. 3-3, 3-4
	Watertube	29(100)	4,3	55^b, 90^c(0.128^b, 0.209^c)	--	Ref. 3-3, 3-4, 3-9
	Watertube	44(150)	1	90^c(0.209^c)	--	Ref. 3-3, 3-4
Natural Gas	Firetube	4.4(15)	8	40(0.093)	75(0.174)	Ref. 3-3, 3-4, 3-10
	Watertube	29(100)	9,11	45^b, 110^c(0.105^b, 0.255^c)		Ref. 3-3, 3-4, 3-9
	Watertube	44(150)	7	$120^c$$(0.280)^c$	--	Ref. 3-3, 3-4

[a] Includes No. 5 and No. 6 fuel oils.
[b] From boilers not equipped with air preheaters.
[c] From boilers equipped with air preheaters.

TABLE 1-2. SUMMARY OF COMBUSTION PROCESS MODIFICATION CONCEPTS

Combustion Conditions	Control Concept	Effect on Thermal NO_x	Effect on Fuel NO_x	Primary Applicable Controls		
				Operational Adjustments	Hardware Modification	Major Redesign
Decrease primary flame zone O_2 level	Decrease overall O_2 level	Reduces O_2 rich, high NO_x pockets in the flame	Reduces exposure of fuel nitrogen intermediaries to O_2	Low excess air firing	Flue gas recirculation (FGR)	
	Delayed mixing of fuel and air	Flame cooling and dilution during delayed mixing reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burner adjustments	Low NO_x burners	Optimum burner/ firebox design
	Primary fuel-rich flame zone	Flame cooling in low O_2, low temp. primary zone reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burners out of service; biased burner firing	Overfire air ports	Burner/firebox design for two stage combustion
Decrease peak flame temperature	Decrease adiabatic flame temperature	Direct suppression of thermal NO_x mechanism	Ineffective	Reduced air preheat	Water injection, FGR	
	Decrease combustion intensity	Increased flame zone cooling yields lower peak temperature	Minor direct effect; indirect effect on mixing	Load reduction		Enlarged firebox, increased burner spacing
	Increased flame zone cooling/ reduce residence time	Increased flame zone cooling yields lower peak temperature	Ineffective	Burner tilt		Redesign heat transfer surfaces, firebox aerodynamics
Chemically reduce NO_x in post flame region	Inject reducing agent	Reduction	Reduction		Ammonia injection possible on some units	Redesign convective section for NH_3 injection

T-1836

  - -- Controlled mixing of fuel and air or use of fuel-rich primary flame zone
  - -- Decreased primary flame zone residence time
- Chemically reduced NO_x in postflame region by:
  - -- Injection of reducing agent

Table 1-2 relates these control concepts to applicable combustion process modifications and equipment types. The process modifications are further categorized according to their role in the control development sequence: operational adjustments, hardware modifications of existing equipment or through factory installed controls, and, major redesigns of new equipment. The controls for decreased O_2 are also generally effective for peak temperature reduction but have not been repeated.

1.3 SYSTEMS OF NO_x EMISSIONS REDUCTION FOR COAL-FIRED BOILERS

The combustion modification controls reviewed for possible application to industrial boilers included

- Low excess air (LEA)
- Staged combustion air (SCA)
  - -- Burners out of service (BOOS), not applicable to stokers
  - -- Overfire (OFA) or sidefire (SFA) air
- Low NO_x burners (LNB)
- Flue gas recirculation (FGR)
- Reduced air preheat (RAP)
- Load reduction (LR) or reduced combustion intensity (furnace redesign)
- Ammonia injection

The following subsections discuss the selection of the best control systems for coal-fired boilers.

1.3.1 Candidate Best Systems of Control for Coal-Fired Boilers

In selecting the best system of NO_x emissions reduction, many factors have to be considered, including:

- Control effectiveness and applicability
- Reliability and availability
- Process impacts
- Capital and operating costs
- Energy impacts
- Environmental impacts

The effectiveness of controls in reducing NO_x emissions, and their applicability to industrial boilers as well as their reliability, were used to select preliminary candidate control systems. Techniques were considered if they were expected to be available for new boilers sold in 1983 or sooner. Performance data for these preliminary candidates were then carefully reviewed to identify any demonstrated or expected process or environmental impacts. For example, major impacts such as severe derating of the boiler can make a control option no longer viable. Environmental impacts were evaluated through the analysis of measured or postulated incremental emissions, other than NO_x, when controls are implemented. Finally, capital and operating costs, including energy impacts, were considered. These costs were used to decide between favorable alternative control options, or in the case of costly but highly effective techniques, to defer application until stringent control levels are absolutely necessary.

All of the above listed factors were considered by evaluating detailed field test results when available and through discussions with major equipment manufacturers and users, and control R&D groups. Throughout this report there is much attention directed toward retrofit field test applications. This is so because retrofit data are the only documented information currently available.

In the ensuing discussion of emission control technologies, candidate technologies were compared using three emission control levels labelled "moderate, intermediate, and stringent." These control levels were chosen only to encompass all candidate technologies and form bases for comparison of technologies for control of specific pollutants considering performance, costs, energy, and environmental effects.

From these comparisons, candidate "best" technologies for control of individual pollutants are recommended for consideration in subsequent industrial boiler studies. These "best technology" recommendations do not consider combinations of technologies to remove more than one pollutant and have not undergone the detailed environmental, cost, and energy impact assessments necessary for regulatory action. Therefore, the levels of "moderate, intermediate, and stringent" and the recommendation of "best technology" for individual pollutants are not to be construed as indicative of the regulations that will be developed for industrial boilers. EPA will perform rigorous examination of several comprehensive regulatory options before any decisions are made regarding the standards for emissions from industrial boilers.

Tables 1-3 and 1-4 list the candidates for best systems of NO_x emissions reduction for pulverized coal-fired and stoker coal-fired boilers, respectively. Also summarized in these tables are the control effectiveness (percent NO_x reduction), operational impact, cost impact which includes energy impact, environmental impact, and commercial availability.

Low Excess Air

Reducing the excess air level in the furnace has generally been found to be an effective method of NO_x control for all fuels. In this technique, the combustion air is reduced to the minimum amount required for complete combustion, maintaining acceptable furnace cleanliness and steam temperature. With less oxygen available in the flame zone, both thermal and fuel NO_x formation are reduced. In addition, the reduced airflow reduces the quantity of flue gas released per unit time resulting in an improvement in boiler efficiency.

Overfire Air

Staged combustion through overfire air seeks to control NO_x by carrying out initial combustion in a primary, fuel-rich, combustion zone, then completing combustion, at lower temperatures, in a second, fuel lean zone. The overfire air technique involves firing the burners (or the combustion bed in the case of stokers) more fuel rich than normal while admitting the remaining combustion air through overfire air ports. Overfire air is very effective for NO_x reduction and may be used with all fuels.

Reduced Combustion Intensity

Reducing combustion intensity generally lowers thermal NO_x formation. Reduced combustion intensity can be brought about by load reduction (reduced firing rate) in existing units and by use of an enlarged firebox in new units. NO_x reduction field tests on industrial boilers have been mixed, on a retrofit basis, but the technique is probably best implemented as increased furnace plan area in new designs, based on results for new utility boilers.

TABLE 1-3. CANDIDATES FOR BEST SYSTEMS OF NO_x EMISSIONS REDUCTION: PULVERIZED COAL-FIRED BOILERS

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact	Availability
Low Excess Air	5 - 25	Increased boiler efficiency.	Increased efficiency offsets capital and operating costs.	Possible increased CO and organic emissions.	Available
Overfire Air	5 - 30	Possible increased slagging, corrosion. Perhaps slight decrease in boiler efficiency.	Major modification. Marginal increase in cost for new units.	Possible increased particulate and organic emissions.	Commercially offered but not demonstrated for this boiler/fuel category
Reduced Combustion Intensity	5 - 25	None. Best implemented as increased furnace plan area in new designs.	Major modification. Marginal increase in cost for new units.	None	Technology transfer required from utility industry
Low NO_x Burners	45 - 60	None expected.	Potentially most cost-effective.	None expected.	1981 - 1983[c]
NH_3 Injection	40 - 60	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modifications.	Possible emissions of NH_3 and byproducts.	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied.

[c] References 2-79, 3-30

TABLE 1-4. CANDIDATES FOR BEST SYSTEMS OF NO_x EMISSIONS REDUCTION: STOKER COAL-FIRED BOILERS

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact	Availability
Low Excess Air	5 - 25	Possible grate overheat, clinker formation, increased corrosion. Close operator attention required.	Increased efficiency should partially offset costs.	Possible increased CO, organic, and particulate emissions.	Available
Overfire Air	5 - 25	Possible grate overheat, clinker formation, increased corrosion. Close operator attention required. Perhaps slight decrease in boiler efficiency.	Major modification of grate and OFA, probably costly. Present units have OFA for smoke control only.	Possible increased CO, organic, and particulate emissions.	R&D
NH_3 Injection	40 - 60	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modifications.	Possible emissions of NH_3 and byproducts.	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly.

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied.

Low NO_x Burners

Low NO_x burners are generally designed to reduce flame turbulence, delay fuel air mixing, and establish fuel-rich zones where combustion initially takes place. The longer, less intense flames produced with low NO_x burners, as compared to those of conventional burners, result in lower flame temperatures which reduce thermal NO_x generation. Moreover, the reduced availability of oxygen in the initial combustion zone inhibits fuel NO_x conversion. Low NO_x burners represent a developing technology that promises highly effective NO_x control at relatively low cost.

Ammonia Injection

The technique reduces NO to N_2 and H_2O with injection of ammonia (NH_3) at flue gas temperatures ranging from 1070 to 1270K (1470 to 1830°F). However, the method is very temperature sensitive with maximum NO_x reductions occurring in a very narrow temperature window around 1240 ± 50K (1770 ± 90°F). An elaborate NH_3 injection, monitoring and control system is required. The application of this technique, especially to the severe flue gas environment from coal combustion, is still several years away.

1.3.2 Best Systems of Control for Coal-Fired Boilers

The best systems of control were selected based on the criteria discussed in the previous subsection, and are summarized in Table 1-5 for boilers with heat input capacity $\geq$29 MW (100 x 10^6 Btu/hr) and Table 1-6 for boilers <29 MW (100 x 10^6 Btu/hr). Best systems were selected by boiler equipment type and suggested moderate, intermediate and stringent level of control. Control effectiveness, operational impact, cost including energy impact, environmental impact, and commercial availability have already been summarized in Tables 1-3 and 1-4. It should be noted that the suggested moderate control levels for the boiler/fuel categories considered are generally conservative in the sense that demonstrated control techniques have, in specific instances, achieved controlled NO_x levels lower than the suggested moderate levels.

Spreader stoker boilers are listed in both Tables 1-5 ($\geq$ 29 MW) and 1-6 (<29 MW) because this design type is offered over a large range of heat input capacities. However, because their average baseline emission levels are relatively higher than those from other stoker designs, it is

TABLE 1-5. BEST CONTROL SYSTEMS FOR COAL-FIRED INDUSTRIAL BOILERS WITH HEAT INPUT $\geq$29 MW (100 x 10^6 Btu/Hr)[a]

Boiler Equipment Type	Baseline NO_x Emissions ng/J (lb/10^6 Btu)	Level of Control		
		Moderate 301 ng/J (0.7 lb/10^6 Btu)	Intermediate 258 ng/J (0.6 lb/10^6 Btu)	Stringent 215 ng/J (0.5 lb/10^6 Btu)
Pulverized Coal-Fired	285 (0.663)[b]	No control necessary[c]	1. Low excess air 2. Overfire air	1. Overfire air* 2. Low NO_x burner*** 3. Ammonia injection[d]**
Spreader Stoker	265 (0.616)	No control necessary	Low excess air	Low excess air/ Overfire air***

[a] Low excess air operation is recommended practice whenever controls are required. However combination of LEA and OFA is not recommended for pulverized coal tangential units (see Section 3.2.1.2).

T-1759

[b] Wide range of baseline emissions reported (see Section 3.2.1.1)

[c] Some units may require low excess air.

[d] NH_3 injection required only for those units with unusually high baseline emissions.

*Commercially offered but not demonstrated for this boiler/fuel category.

**Commercially offered buy not demonstrated.

***Under research and development.

TABLE 1-6. CANDIDATE BEST CONTROL SYSTEMS FOR COAL-FIRED INDUSTRIAL BOILERS WITH HEAT INPUT <29 MW (100 x 10^6 Btu/Hr)

Boiler Equipment Type	Baseline NOx Emissions ng/J (lb/10^6 Btu)	Level of Control		
		Moderate 215 ng/J (0.5 lb/10^6 Btu)	Intermediate 172 ng/J (0.4 lb/10^6 Btu)	Stringent 129 ng/J (0.3 lb/10^6 Btu)
Spreader Stoker	265(0.616)	Low excess air/overfire air***	Ammonia injection**	Ammonia injection**
Chain Grate	140(0.326)	No control necessary	No control necessary	Low excess air
Underfeed	150(0.349)	No control necessary	No control necessary	Low excess air

**Commercially offered but not demonstrated.
***Under research and development.

recommended that spreader stokers be grouped with pulverized coal units as far as potentially achievable emission control levels are concerned. Spreader stokers are listed together with other stoker types in Table 1-6 solely because of similarities in designs and hence in applicable control techniques.

Pulverized Coal-Fired Boilers

Low excess air or overfire air form the best system for moderate (301 ng/J, 0.7 lb/10^6 Btu) and intermediate (258 ng/J, 0.6 lb/10^6 Btu) NO_x control for pulverized coal-fired industrial boilers. The moderate control level was not set lower than 301 ng/J because of the broad range in baseline NO_x emissions for the six units tested, ranging from 174 to 563 ng/J with most data from 201 to 296 ng/J, yielding an average baseline of 285 ng/J. No significant correlation of emission levels with (pulverized coal) boiler type or coal properties were evident from the limited data.

Staged combustion with low excess air and overfire air should achieve the stringent control level of 215 ng/J (0.5 lb/10^6 Btu). The low excess air and overfire air control system has the primary advantage over the other control systems because of its commercial availability and its effectiveness. The cost of the system is not prohibitive when overfire air ports are designed as a part of new boilers. In addition, careful operation of staged air injection is not expected to seriously affect emissions of other criteria pollutants. Burner stoichiometries in the range of 100 to 110 percent would be adequate to achieve a 20 percent NO_x reduction. At these stoichiometry levels, oxidizing atmospheres would prevail in the furnace, thus minimizing concern over possible furnace slagging and boiler tube wastage. However, achieving the stringent NO_x emission level of 215 ng/J with combined low excess air and overfire air may require burner stoichiometries be reduced below 100 percent in some cases. This low burner stoichimetry level would cause reducing atmospheres in parts of the furnace, thus creating the potential for corrosion of water tubes. Generally boiler manufacturers do not recommend burner operation with stoichimetry levels below 100 percent primarily because of increased corrosion potential. Therefore, low excess overfire air is recommended as the stringent control technique with the provision that further field testing and demonstrations may be necessary.

Because of the possible operational problems associated with overfire air, low NO_x burners were selected as the first backup candidate for achieving the stringent control level. Reported NO_x reduction efficiencies for utility size units are of the order of 45 to 60 percent. Similar reduction efficiencies are projected for the industrial low NO_x burners under development. Therefore low NO_x burners are expected to easily meet the 215 ng/J control level, a 25 percent reduction from the average baseline level. Once developed, low NO_x coal-fired burners for industrial boilers could become the best control system because of the expected lower cost and other operational advantages over the staged combustion method of overfire air.

If low NO_x burners are not commercialized by 1983, ammonia injection is the alternative stringent contol system. However, NH_3 injection is several times more costly than conventional combustion modification controls. In addition, as a developing technology, there are several implementation and operational problems that need to be resolved. The optimal effectiveness for noncatalytic reduction of NO by NH_3 occurs over a very narrow temperature range, around 1240 ± 50K (1770 ± 90^0F). Hence, precise location of the NH_3 injection ports is crucial. Since the temperature profile in a boiler changes with load, NO_x control with NH_3 may dictate load restrictions on the boiler. Other potential problems include fouling and emissions of NH_3 and byproducts. However, a major strength of the technique is its potential for high NO_x removal (40 to 60 percent).

Stoker Coal-Fired Boilers

Spreader stokers are the only major stoker boiler types with average uncontrolled NO_x emissions above 258 ng/J (0.6 lb/10^6 Btu). Low excess air and overfire air constitute the best candidate control system capable of reductions to 215 ng/J (0.5 lb/10^6 Btu). However, close operator attention will be required to avoid the problems of grate overheat, clinker formation, and corrosion associated with firing at too low excess air levels. Potential environmental impacts as increased carbon monoxide, particulate, and organic emissions warrant further testing. Any NO_x reduction below 215 ng/J (0.5 lb/10^6 Btu) can only be achieved with NH_3 injection (an unproven technique), possibly down to 129 ng/J (0.3 lb/10^6 Btu).

The other major stoker types, chain grate and underfeed, have average uncontrolled NO_x emissions below 172 ng/J (0.4 lb/10^6 Btu). Control of these units to 129 ng/J (0.3 lb/10^6 Btu) is possible with low excess air. It should be emphasized that control data for stokers are limited, and low excess air and overfire air represent the only significant controls tested on stokers.

1.4 SYSTEMS OF NO_x EMISSIONS REDUCTION FOR OIL-FIRED BOILERS

The combustion modification NO_x control techniques considered for oil-fired boilers are the same as those for coal-fired units, as listed at the beginning of Subsection 1.3.

1.4.1 Candidate Best Systems of Control for Oil-Fired Boilers

Using the selection procedure discussed earlier, candidate best control systems were identified and are listed in Table 1-7 for residual oil-fired boilers and Table 1-8 for distillate oil-fired boilers units. Also summarized in these tables are the control effectiveness (percent NO_x reduction), operational impact, cost impact which includes energy impact, environmental impact, and commercial availability. All of these candidates, except for flue gas recirculation and reduced air preheat have been described in the previous subsection on coal-firing.

Flue gas recirculation for NO_x control consists of extracting a portion of the flue gas and returning it to the furnace, admitting the flue gas through the burner windbox. Flue gas recirculation lowers the bulk furnace gas temperature and reduces oxygen concentration in the combustion zone. The former effect is probably dominant since flue gas recirculation has been found to be most effective in reducing thermal NO_x. Addition of flue gas recirculation to a boiler is a major modification: the fan, ductwork, dampers, and controls as well as possibly having to increase existing fan capacity due to increased draft loss, can represent a large investment.

Reducing the amount of combustion air preheat lowers the primary combustion zone peak temperature, generally lowering thermal NO_x production as a result. It is an effective technique applicable to the clean fuels: distillate oil and natural gas. However, to prevent severe energy penalties, an economizer should be substituted as a flue gas heat recovery device.

TABLE 1-7. CANDIDATES FOR BEST SYSTEMS OF NO_x EMISSIONS REDUCTION: RESIDUAL OIL-FIRED BOILERS

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact	Availability
Low Excess Air	5 - 20	Increased boiler efficiency.	Increased efficiency partially offsets costs.	Possible increased CO and organic emissions.	Available
Staged Combustion	20 - 40	Perhaps slight decrease in boiler efficiency.	Major modification, perhaps costly.	Possible increased particulate and organic emissions.	Commercially offered but not demonstrated for this boiler/fuel category
Low NO_x Burners	20 - 50	None expected.	Potentially most cost-effective.	None expected.	Commercially offered but not demonstrated
NH_3 Injection	40 - 70	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modification.	Possible emissions of NH_3 and byproducts.	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly.

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied.

TABLE 1-8. CANDIDATES FOR BEST SYSTEMS OF NO_x EMISSIONS REDUCTION: DISTILLATE OIL- AND GAS-FIRED BOILERS

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact	Availability
Low Excess Air	5 - 15 (oil), 5 - 10 (gas)	Increased boiler efficiency.	Increased efficiency should offset some of costs.	Possible increased CO and organic emissions.	Available
Staged Combustion	20 - 40 (oil), 25 - 45 (gas)	Perhaps slight decrease in boiler efficiency.	Major modification, probably costly.	Possible increased organic emissions.	Commercially offered but not demonstrated for this boiler/fuel catetory
Flue Gas Recirculation	40 - 70 (oil) 45 - 75 (gas)	Possible flame instability. Can be eliminated with proper engineering/testing.	Major modification, probably costly.	Possible increased organic emissions.	Available
Reduced Air Preheat	20 - 55 (oil) 20 - 55 (gas)	Replacing air preheater with economizer in new designs.	None, other than engineering redesign of new units (if necessary).	None	Available
Low NO_x Burners	20 - 50	None expected.	Potentially most cost-effective.	None expected.	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly.

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied.

1.4.2 Best Systems of Control for Oil-Fired Boilers

Best systems of control for residual oil- and distillate oil-fired boilers are summarized in Tables 1-9 and 1-10, respectively. Best systems were selected by boiler equipment type and suggested moderate, intermediate, and stringent level of control.

Residual Oil-Fired Boilers

Since baseline NO_x emissions from residual oil-fired firetube boilers averaged only 115 ng/J (0.267 lb/10^6 Btu) no controls are generally necessary to meet the moderate control level of 129 ng/J (0.3 lb/10^6 Btu). Low excess air firing should achieve the intermediate level of control, 108 ng/J (0.25 lb/10^6 Btu). Low excess air operation should also increase boiler efficiency. The same caution about possible increased CO and organic emissions discussed for coal-firing under low excess air apply here also. Stringent control, 86 ng/J (0.2 lb/10^6 Btu), will require either low NO_x burners or staged combustion, neither one of which is demonstrated technology for the small firetube designs. Low NO_x burners were selected as the first choice because of their potential for being the most cost-effective, high-reduction combustion modification technique.

The generally larger watertube boilers with higher NO_x emissions will also need the same controls, low excess air, low NO_x burners, and staged combustion, only sooner (e.g., moderate level). Staged combustion is a demonstrated technique for the large multiburner watertube boilers. However, if low NO_x burners are commercialized in time for stringent control, 86 ng/J (0.2 lb/10^6 Btu), they should prove more cost-effective. The only other alternative for stringent control is ammonia injection. Although demonstrated and in limited commercial operation for oil- and gas-firing in Japan, this control system represents a severalfold more costly alternative for NO_x reduction than the other two systems. In addition, operational problems and potential emissions of NH_3 and byproducts cause environmental concern.

It should be noted that the above discussed controlled emission levels for residual oil firing may be difficult to achieve for boilers firing high nitrogen content fuel (e.g., >0.3 weight percent nitrogen). Indeed there is a possible trend of increasing total NO_x emissions with fuel nitrogen content, unlike the behavior exhibited by coal-fired

TABLE 1-9. BEST CONTROL SYSTEM FOR RESIDUAL OIL-FIRED INDUSTRIAL BOILERS[a]

Boiler Equipment Type	Baseline NO_x Emissions ng/J (lb/10^6 Btu)	Level of Control		
		Moderate 129 ng/J (0.3 lb/10^6 Btu)	Intermediate 108 ng/J (0.25 lb/10^6 Btu)	Stringent 86 ng/J (0.2 lb/10^6 Btu)
Firetube	115 (0.267)	No control necessary	Low excess air	1. Low NO_x burners** 2. Staged combustion***
Watertube	160 (0.372)	1. Low excess air 2. Low NO_x burners** 3. Staged combustion*	1. Low NO_x burners** 2. Staged combustion*	1. Low NO_x burners** 2. Ammonia injection**

[a] Low excess air is recommended practice whenever controls are required.

T-1760

*Commercially offered but not demonstrated for this boiler/fuel category.
**Commercially offered but not demonstrated.
***Research and development.

TABLE 1-10. BEST CONTROL SYSTEMS FOR DISTILLATE OIL-FIRED INDUSTRIAL BOILERS[a]

Boiler Equipment Type	Baseline NO_x Emissions ng/J (lb/10^6 Btu)	Level of Control		
		Moderate 86 ng/J (0.2 lb/10^6 Btu)	Intermediate 65 ng/J (0.15 lb/10^6 Btu)	Stringent 43 ng/J (0.1 lb/10^6 Btu)
Firetube	75 (0.175)	No control necessary	Low excess air	1. Flue gas recirculation 2. Low NO_x burners**
Watertube not equipped with air preheater	55 (0.128)	No control necessary	No control necessary	1. Flue gas recirculation 2. Low NO_x burners** 3. Staged combustion air*
Watertube equipped with air preheater	90 (0.209)	Low excess air	1. Reduced air preheat 2. Flue gas recirculation 3. Low NO_x burners** 4. Staged combustion*	1. Reduced air preheat + flue gas recirculation 2. Reduced air preheat + Low NO_x burners**

[a] Low excess air operation is recommended practice whenever controls are required

T-1761

*Commercially offered but not demonstrated for this boiler/fuel category.

**Commercially offered but not demonstrated.

boilers. A possible controlled (low excess air operation) NO_x level is 200 ng/J (0.47 lb/10^6 Btu) for high nitrogen content residual oil.

Distillate Oil-Fired Boilers

NO_x emissions from distillate oil combustion are primarily from thermal NO_x formation. The relatively low uncontrolled baseline NO_x emissions of distillate oil-fired boilers permit achievement of very low controlled NO_x levels: 86, 65, and 43 ng/J (0.2, 0.15, and 0.1 lb/10^6 Btu). These control levels can in most cases be met with commercially available techniques. Table 1-10 lists the best control systems for moderate, intermediate, and stringent control of distillate oil-fired boilers. The preferred control systems are low excess air, reduced air preheat, flue gas recirculation, and low NO_x burners, in that order, lowering NO_x down to 65 ng/J (0.15lb/10^6 Btu). Distillate oil- and natural gas-fired boilers not equipped with air preheaters (all firetubes, some watertubes) exhibited significantly lower NO_x emissions than those with air preheaters, irrespective of boiler heat input capacity. Those boilers without air preheat can reach 43 ng/J (0.1 lb/10^6 Btu) with just flue gas recirculation, while air preheater- equipped boilers require combined reduced air preheat and flue gas recirculation.

Replacing the air preheater with an economizer in a new boiler is the best way to implement reduced air preheat with no energy loss. Flue gas recirculation, combined with reduced air preheat, is the best stringent control technique because of its demonstrated high effectiveness for clean fuels (distillate oil and natural gas). Potential operational problems such as flame instability should be eliminated with proper engineering and testing. Environmental impacts such as possible increased organic emissions are expected to be minimal, although further investigation is definitely called for.

1.5 SYSTEMS OF NO_x EMISSION REDUCTION FOR GAS-FIRED BOILERS

The NO_x emissions characteristics and control strategies for gas-fired boilers are nearly identical to those for distillate oil-fired units. Therefore, the discussion in the previous subsection on distillate oil-firing is directly relevant here and will not be repeated. Table 1-8 summarizes the candidates for best system of reduction, while Table 1-11 summarizes the best control systems and levels of control achievable.

1.6 ENERGY IMPACT

Although energy considerations were certainly included in the selection of best controls discussed in Sections 1.3 through 1.5, a general summary of energy impacts of combustion modification NO_x controls is useful here. Of the control methods reviewed, low excess air is the most fuel efficient. Low excess air should be used with most control methods to increase thermal efficiency and reduce NO_x emissions. Staged combustion air ports can be located so that thermal efficiency is not decreased if they are used with low excess and only one type of fuel is burned. For boilers that burn several fuels, several air ports would be needed and these ports may not always be in just the optimal location. Except for increased fan power use, boilers could be designed so that flue gas recirculation would not decrease thermal efficiency significantly. In some tests this was not always the case. Low NO_x burners are the most promising new technology. Ignoring NH_3 and carrier gas, ammonia injection appears to have only a minor energy impact though for raw material consumption, operational, and environmental reasons it might not be desirable. For new distillate oil- and gas-fired boilers, economizers are recommended over air preheaters as energy saving devices.

In summary, combustion modification NO_x controls for new industrial boilers should only have a minor energy impact. In fact, with proper boiler design and control implementation, it might even be possible in some cases to significantly lower NO_x emissions and use less energy.

1.7 COST IMPACT

Although cost considerations were certainly included in the selection of best controls discussed in Sections 1.3 through 1.5, a general summary of cost impacts of combustion modification NO_x controls is useful here.

The primary contributions of combustion modification NO_x controls to steam costs changes are the equipment modification costs and changes in thermal efficiency and fan power demand. For firetube boilers annualized equipment costs are usually higher than costs due to efficiency or fan power demand changes. For watertube boilers, the opposite is usually true. For both firetube and watertube boilers, all costs are important and any factors that can lower any of these costs will be beneficial. In

TABLE 1-11. BEST CONTROL SYSTEMS FOR NATURAL GAS-FIRED INDUSTRIAL BOILERS[a]

Boiler Equipment Type	Baseline NO_x Emissions ng/J (lb/10^6 Btu)	Level of Control: Moderate 86 ng/J (0.2 lb/10^6 Btu)	Level of Control: Intermediate 65 ng/J (0.15 lb/10^6 Btu)	Level of Control: Stringent 43 ng/J (0.1 lb/10^6 Btu)
Firetube	40 (0.093)	No control necessary	No control necessary	No control necessary
Watertube not equipped with air heater	45 (0.105)	No control necessary	No control necessary	Low excess air
Watertube equipped with air heater	110 (0.256)	1. RAP[b] 2. FGR 3. SCA* 4. LNB**	1. RAP + FGR[b] 2. RAP + LNB** 3. RAP + SCA*	1. RAP + FGR[b] 2. RAP + LNB** 3. RAP + NH_3** injection

[a] Low excess air operation is recommended practice whenever controls are required.

[b] RAP = Reduced Air Preheat
FGR = Flue Gas Recirculation
SCA = Staged Combustion Air
LNB = Low NO_x Burners

T-1762

*Commercially offered but not demonstrated for this boiler/fuel category.
**Commercially offered but not demonstrated.

many cases, using the lowest possible excess air will lower the cost impact. Of course, the boiler should be designed to give the highest possible thermal efficiency and lowest fan power requirements. Careful design can result in better fuel efficiency than was assumed in the economic analysis presented in this report.

Figures 1-1, 1-2, and 1-3 summarize the cost effectiveness of typical combustion modification NO_x controls for representative coal-, residual oil-, and distillate oil-/natural gas- fired industrial boilers. The estimated annualized control cost is plotted as a function of achievable NO_x control level.

Of the NO_x controls covered in this report, low excess air is the method recommended to be considered first since it can reduce fuel costs. Low NO_x burners are a promising technique since they should allow both low NO_x and low excess air operation, and thus save fuel while lowering NO_x emissions. Staged combustion is the next best method, unless fuel switching problems make it impractical. If staged combustion cannot be used, flue gas recirculation is the next most cost-effective technique. Ammonia injection is the least cost effective technique and load changing may make it very impractical. Also, whenever possible, an economizer is preferred over an air preheater as a fuel saving device since it does not raise NO_x levels.

In summary, combustion modification NO_x controls, once proven and demonstrated, should be a cost effective means of control for industrial boilers raising steam costs up to only 1 to 2 percent in most cases. However, the initial investment required, especially for small boilers, may be a large fraction of the cost of the boiler itself, up to 25 percent when controls are installed on a new boiler and up to 50 percent when retrofitting the controls on an existing boiler. Factory installed controls on new boilers should prove more cost effective than retrofit controls.

1.8 ENVIRONMENTAL IMPACT

Although environmental considerations were certainly included in the selection of best control discussed in Sections 1.3 through 1.5, a general summary of environmental impacts of combustion modification NO_x controls is useful here.

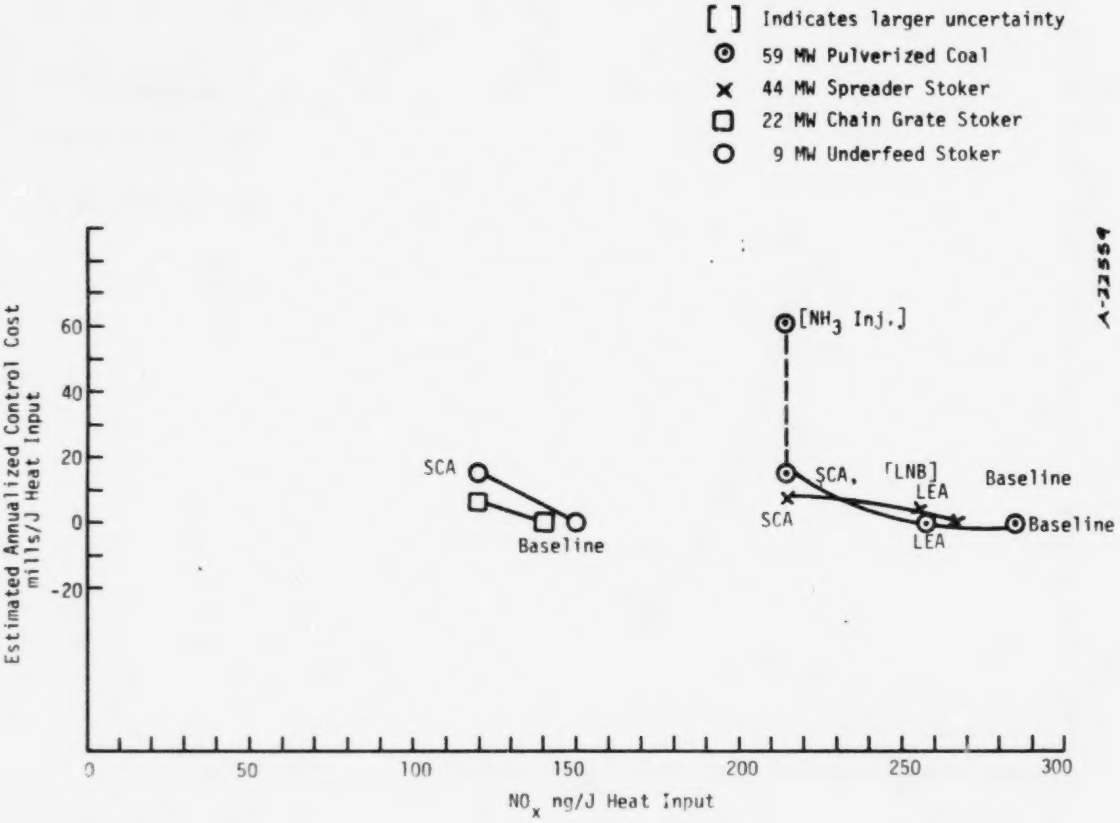

Figure 1-1. Estimated annualized control cost versus NO$_x$ level for coal-fired boilers (costs are only first estimates).

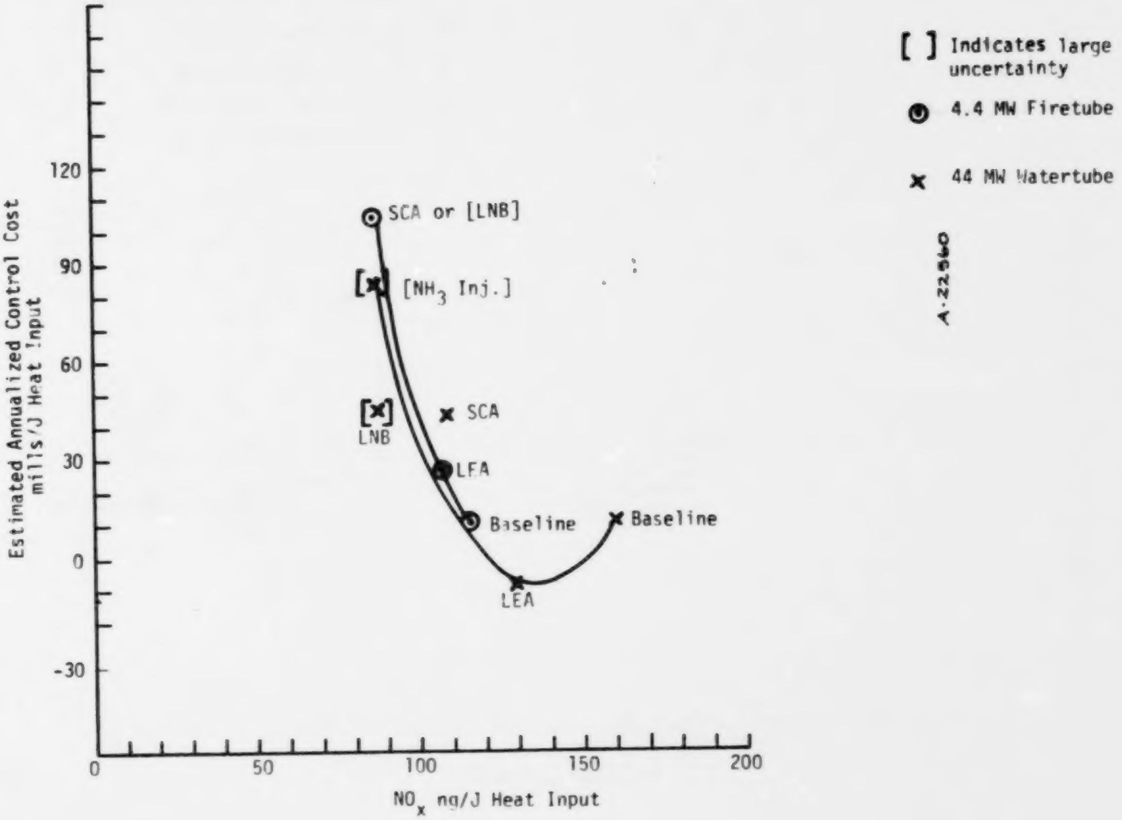

Figure 1-2. Estimated annualized control cost versus NO_x emission level for residual oil-fired boilers (costs are only first estimates).

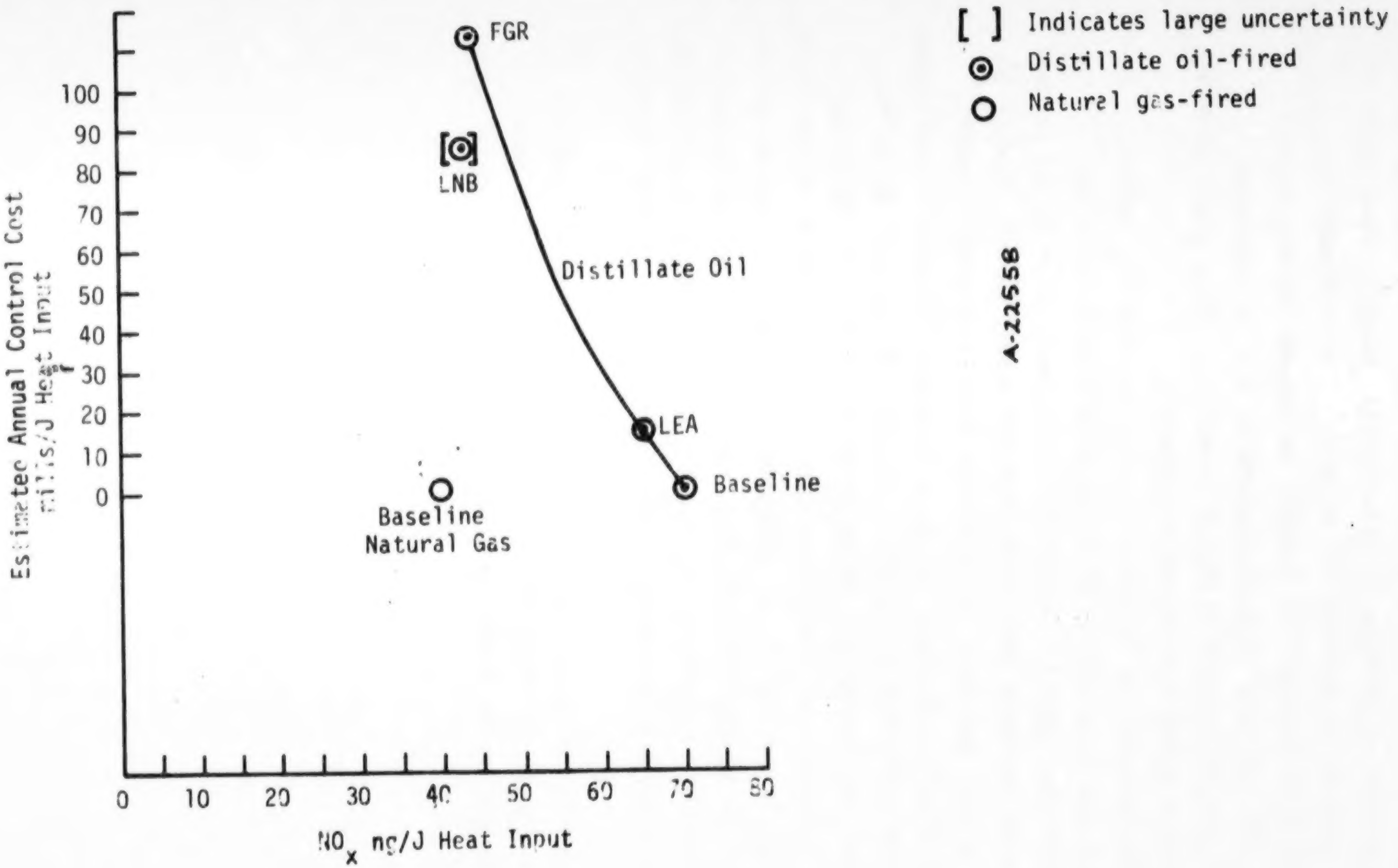

Figure 1-3. Estimated annualized control cost versus NO$_x$ emission levels for distillate oil and natural gas fired 4.4 MW firetube boiler (costs are first estimates only).

In general, no serious environmental impacts are expected for the control techniques recommended in this report. However, more field testing is required to quantify and establish that statement.

Tables 1-12 through 1-15 compare the recommended NO_x control techniques, the levels of control achievable, and the resulting incremental changes in other pollutant emissions. Where actual data are not available, a postulated effect is presented.

Carbon monoxide levels generally increase with NO_x control, although this can be minimized if not eliminated with judicious application of the control. Actual test data shows unburned hydrocarbon emissions to be decreased more often than increased, though the data are variable. Sulfate emissions decrease with decreasing oxygen content; particulate emissions decrease due to an (assumed) increase in particulate control device collection efficiency. The best NO_x control device for industrial boilers firing coal appear to be low excess air and staged combustion (overfire air), but information is too limited to be conclusive.

Low excess air and staged combustion (overfire air) appears to have little effect on incremental emissions from residual oil-fired boilers. For distillate oil- and natural gas-fired boilers, flue gas recirculation, staged combustion, and reduced air preheat appear to be the best methods available.

Incremental emissions are potentially increased by NO_x controls. More data are needed to quantify the incremental emissions for each control technique and to determine if any significant environmental impact may result.

TABLE 1-12. POSTULATED EFFECT OF CANDIDATE NO_x CONTROL SYSTEMS ON INCREMENTAL EMISSIONS FROM COAL-FIRED INDUSTRIAL BOILERS

Boiler	NO_x Control Technique	Level of Control	Change in Incremental Emissions			
			CO	UHC	SO_3	Particulate
Coal-Fired Boiler ≥29 MW	Low Excess Air	Moderate	+	-	(-)	(-)[a]
		Intermediate	+	-	-	-
		Stringent	+	v	-	-
	Overfire Air	Intermediate	+	(+)	(-)	(-)[a]
		Stringent	+	+	-	(-)[a]
	Low NO_x Burners	Stringent	(+)	(+)	(-)	(-)[a]
	Ammonia Injection[b]	Stringent	(NE)	(NE)	(+)	(NE)
Coal-Fired Boilers < 29 MW	Low Excess Air	Intermediate	-	+	(-)	-
		Stringent	v	(+)	(-)	(-)[a]

T-1453

( )	No data available
-	Some decrease
+	Some increase
++	Significant increase
v	Variable results
NE	No effect

[a] Assuming dust control devices are utilized, otherwise (+)

[b] Ammonia injection may cause ammonia and byproduct emissions

TABLE 1-13. POSTULATED EFFECT OF CANDIDATE NO_x CONTROL SYSTEMS ON INCREMENTAL EMISSIONS FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS

NO_x Control Technique	Level of Control	Change in Incremental Emissions			
		CO	UHC	SO_3	Particulate
Low Excess Air	Moderate	+	(+)	(-)	-
	Intermediate	+	v	-	-
	Stringent	++	v	-	-
Overfire Air	Moderate	(+)	(+)	(-)	(-)[a]
	Intermediate	+	+	(-)	-
	Stringent	+	+	-	-
Low NO_x Burners	Intermediate	(+)	(+)	(-)	(-)[a]
	Stringent	(+)	(+)	(-)	(-)[a]
Ammonia Injection[b]	Stringent	(NE)	(NE)	(+)	(NE)

( )	No data available
-	Some decrease
+	Some increase
++	Significant increase
a	Assuming dust control devices are utilized. Otherwise (+)
b	Ammonia injection may cause ammonia and byproduct emissions
v	Variable results
NE	No Effect

TABLE 1-14. POSTULATED EFFECT OF CANDIDATE NO_x CONTROL SYSTEMS ON INCREMENTAL EMISSIONS FROM DISTILLATE OIL-FIRED INDUSTRIAL BOILERS

NO_x Control Technique	Level of Control	Change in Incremental Emissions			
		CO	UHC	SO_3	Particulate
Low Excess Air	Moderate	(+)	(+)	(-)	(-)[a]
	Intermediate	++	-	(-)	(-)[a]
	Stringent	(++)	(+)	(-)	(-)[a]
Flue Gas Recirculation	Moderate	(+)	(+)	(-)	(-)[a]
	Intermediate	(+)	(+)	(-)	(-)[a]
	Stringent	+	+	(-)	(-)[a]
Overfire Air	Moderate	(+)	(+)	(-)	(-)[a]
	Intermediate	+	+	(-)	-
	Stringent	+	+	-	-
Reduced Air Preheat	Intermediate	(NE)	(NE)	(-)	(+)
	Stringent	(NE)	(NE)	(-)	(+)
Low NO_x Burners	Stringent	(+)	(+)	(-)	(-)[a]

( ) No data available
- Some decrease
+ Some increase
++ Significant increase
a Assuming dust control devices are utilized. Otherwise (+)
NE No Effect

TABLE 1-15. POSTULATED EFFECT OF CANDIDATE NO_x CONTROL SYSTEMS ON INCREMENTAL EMISSIONS FROM GAS-FIRED INDUSTRIAL BOILERS

NO_x Control Technique	Level of Control	Change in Incremental Emissions[a]	
		CO	UHC
Low Excess Air	Moderate	+	(+)
	Intermediate	+	-
	Stringent	+	(+)
Flue Gas Recirculation	Moderate	(+)	(+)
	Intermediate	(+)	(+)
	Stringent	-	(+)
Overfire Air	Moderate	+	(+)
	Intermediate	+	(+)
	Stringent	-	-
Reduced Air Preheat	Moderate	+	-
	Intermediate	+	(+)
	Stringent	+	(+)
Low NO_x Burners	Stringent	(+)	(+)

( ) No data available
- Some decrease
+ Some increase
++ Significant increase
[a] SO_3 and particulate not present in natural gas combustion products

SECTION 2

EMISSION CONTROL TECHNIQUES

This section presents a survey of applicable combustion modifications to reduce NO_x emissions from industrial boilers. Industrial boilers can be defined as coal-, oil- or natural gas-fired steam generators with heat input capacities usually ranging from 3 to 73 MW (10 to 250 x 10^6 Btu/hr). In fact, the current New Source Performance Standards (NSPS) for utility boilers cover units >73 MW (>250 x 10^6 Btu/hr) input (Reference 2-1). However, for the purposes of this study, industrial units larger than 73 MW (250 x 10^6 Btu/hr) are also covered. Indeed, nearly 14 percent of the total population of steam generators in the industrial sector have capacities greater than 73 MW (250 x 10^6 Btu/hr).

This section provides a review of current available knowledge of the effectiveness, applicability and limitations of specific combustion modifications for each major equipment/fuel category in the industrial boiler sector. Major equipment and fuel categories for industrial boilers have been identified as follows:

- Coal-fired
  - Pulverized coal, field-erected watertube
  - Packaged and field erected stoker-fed watertube
- Oil-fired
  - Residual oil, packaged and field erected watertube
  - Residual oil, packaged firetube
  - Distillate oil, packaged and field erected watertube
  - Distillate oil, packaged firetube

- Gas-fired
    - -- Packaged and field erected watertube
    - -- Packaged firetube

The category of stokers includes packaged underfeed units and field erected spreader and chain grate units. These boiler categories include the standard boiler types identified in the current EPA study of which this work is a part (Reference 2-3).

However, the above list contains three additional industrial boiler categories. These are gas- and distillate oil-fired watertube units and residual oil-fired firetube units. These additional boiler types have been selected primarily on two criteria. First, these boiler types have different NO_x emissions characteristics and hence have different control options. Second, a significant number of boilers within these three categories have been extensively tested with combustion modifications. This will be borne out in the subsequent sections. Thus a separate discussion of these units is warranted.

The main discussion on combustion modifications for NO_x control of industrial boilers is preceded by a brief overview of the mechanisms of NO_x formation and the basic concepts for its reduction.

2.1 NO_x FORMATION MECHANISM AND PRINCIPLES OF CONTROL

Oxides of nitrogen formed in combustion processes are usually due either to thermal fixation of atmospheric nitrogen in the combustion air, leading to "thermal NO_x", or to the conversion of chemically bound nitrogen in the fuel, leading to "fuel NO_x".* For natural gas and light distillate oil firing, nearly all NO_x emissions result from thermal fixation. With residual oil, crude oil, and coal, the contribution from fuel-bound nitrogen can be significant and, under certain operating conditions, predominant. A brief discussion of each of these two mechanisms of NO_x formation follows.

2.1.1 Thermal NO_x

The detailed chemical mechanism by which molecular nitrogen in the combustion air is converted to nitric oxide is not fully understood.

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*The term NO_x includes all oxides of nitrogen, primarily NO and NO_2. However, field test data have shown that over 95 percent of the NO_x formed in steam generators leaves the stack as NO (Reference 2-4).

In practical combustion equipment, particularly for liquid or solid fuels, the kinetics of the N_2-O_2 system are coupled to the kinetics of hydrocarbon oxidation and both are influenced, if not dominated, by effects of turbulent mixing in the flame zone. It is, however, generally accepted that thermal NO_x forms at high temperatures in an excess of O_2. The most widely accepted set of reactions that describes this phenomenon is the chain mechanism proposed by Zeldovich (Reference 2-5):

$$N_2 + O \rightleftarrows NO + N \tag{2-1}$$

$$N + O_2 \rightleftarrows NO + O \tag{2-2}$$

$$N + OH \rightleftarrows NO + H \tag{2-3}$$

Reaction (2-1) has a large activation energy (317 kJ/mol) and is generally believed to be rate determining. Oxygen atom concentrations are assumed to have reached equilibrium according to:

$$O_2 + M \rightleftarrows O + O + M \tag{2-4}$$

where M denotes any third substance (usually N_2).

Experimental measurements of NO formation in heated mixtures of N_2, O_2 and Ar at atmospheric pressures have shown that NO concentration is strongly dependent on temperature (Reference 2-6). Thermal NO_x formation is also dependent on the N_2 concentration, the residence time, and the square root of O_2 concentration according to the following equation (Reference 2-6):

$$[NO] = k_1 e^{\left(-k_2/T\right)} [N_2] [O_2]^{1/2} t$$

where: [ ] = mole fraction

T = temperature (K)

t = residence time

k_1, k_2 = constants

Therefore, the formation of thermal NO_x can be reduced by four tactics: (1) reduce nitrogen level, (2) reduce oxygen level, (3) reduce peak temperature, and (4) reduce time of exposure at peak temperature. In typical hydrocarbon-air flames, the N_2 mole fraction is of the order 0.7 and is relatively difficult to modify. Therefore, field practice has focused on reducing oxygen level, peak temperature, and time of exposure in the NO_x-producing region of the combustor (Reference 2-7). These parameters are in turn dependent on secondary combustion variables such as combustion intensity and internal mixing in the flame zone -- effects which are ultimately determined by primary equipment and fuel parameters over which the combustion engineer has some control.

Combustion modification techniques such as lowered excess air and staged combustion have been used to lower local O_2 concentrations. Flue gas recirculation and reduced air preheat have been used in boilers to lower peak flame temperatures. Flue gas recirculation reduces residence time at peak temperatures, although the primary effect is through temperature reduction and lowered O_2 concentration.

Controlling the mixing between fuel, combustion air and recirculated products has also been found to reduce thermal NO_x formation. Burner swirl, combustion air velocity, fuel injection angle and velocity, burner divergent angle and confinement ratio all affect the mixing between fuel combustion air and recirculated products. Unfortunately, generalizing these effects is difficult, because the interactions are complex. Increasing swirl, for example, may both increase entrainment of cooled combustion products (hence lowering peak temperatures) but it may also increase fuel/air mixing (raising local combustion intensity). Thus, the net effect of increasing swirl can be to either raise or lower NO_x emissions, depending on other system parameters (Reference 2-10).

2.1.2 Fuel NO_x

The role of fuel-bound nitrogen as a source of NO_x emissions from combustion sources has been recognized since 1968 (Reference 2-8). Although the relative contribution of fuel and thermal NO_x to total NO_x emissions from sources firing nitrogen-containing fuels has not been definitively established, recent estimates indicate that fuel NO_x is significant and may even predominate. In fact, laboratory studies under controlled operating conditions have shown that fuel NO_x can account for 50 percent of the total NO_x for residual oil and up to 80 percent for coal (Reference 2-9). Therefore, as coal is increasingly used as a national energy source, the control of fuel NO_x will become more important.

The following discussion is directed mainly toward fuel NO_x formation from coal, though fuel NO_x is also a problem with other nitrogen-containing fuels as well. A recent review of published data indicated that, in general, anywhere from 20 to 90 percent of fuel nitrogen in oil is converted to NO_x while the percentage of fuel nitrogen converted to NO_x in coal ranges from 5 to 60 (Reference 2-10). Figure 2-1 illustrates the nitrogen content of various U.S. coals, expressed as ng NO_2 produced per Joule for 100 percent conversion of the fuel nitrogen. The figure clearly shows that if all coal-bound nitrogen was converted to NO_x, emissions for all coals would exceed the coal-fired utility boiler NSPS of 301 ng/J (0.7 lb/10^6 Btu) implemented in 1971. Fortunately, only a fraction of the fuel nitrogen is converted to NO_x for both oil and coal firing (Reference 2-11, 2-12). Furthermore, the percentage of fuel nitrogen conversion appears to decrease as the fuel nitrogen content increases. Recent data from combustion of coal in utility boilers exhibited fuel nitrogen conversion ranging from 6.5 percent to 15 percent, with the possible correlation of conversion increasing with the ratio of coal oxygen to coal nitrogen (References 2-72 and 2-73). An EPA field test program on industrial boilers confirmed the trend of increasing fractional conversion of fuel nitrogen with decreasing nitrogen content. An average conversion of 46 percent was found for residual oil, and nearly 100 percent for distillate oil (Reference 2-20).

Thus, although fuel NO_x emissions undoubtedly increase with increasing fuel nitrogen content, the emissions increase is not proportional (Reference 2-11). In fact, data on tangential coal-fired boilers indicate only a slight increase in total NO_x emissions as fuel nitrogen increases. This is shown in Figure 2-2 (Reference 2-13). One recent report comparing two similar wall-fired utility boilers claimed a 23 percent reduction in fuel NO_x with a 15 percent reduction in fuel nitrogen, on a ng nitrogen/J heat input basis (Reference 2-70). However the lower NO_x producing coal also had a higher moisture content which would have tended to reduce NO_x emissions. The data collected on

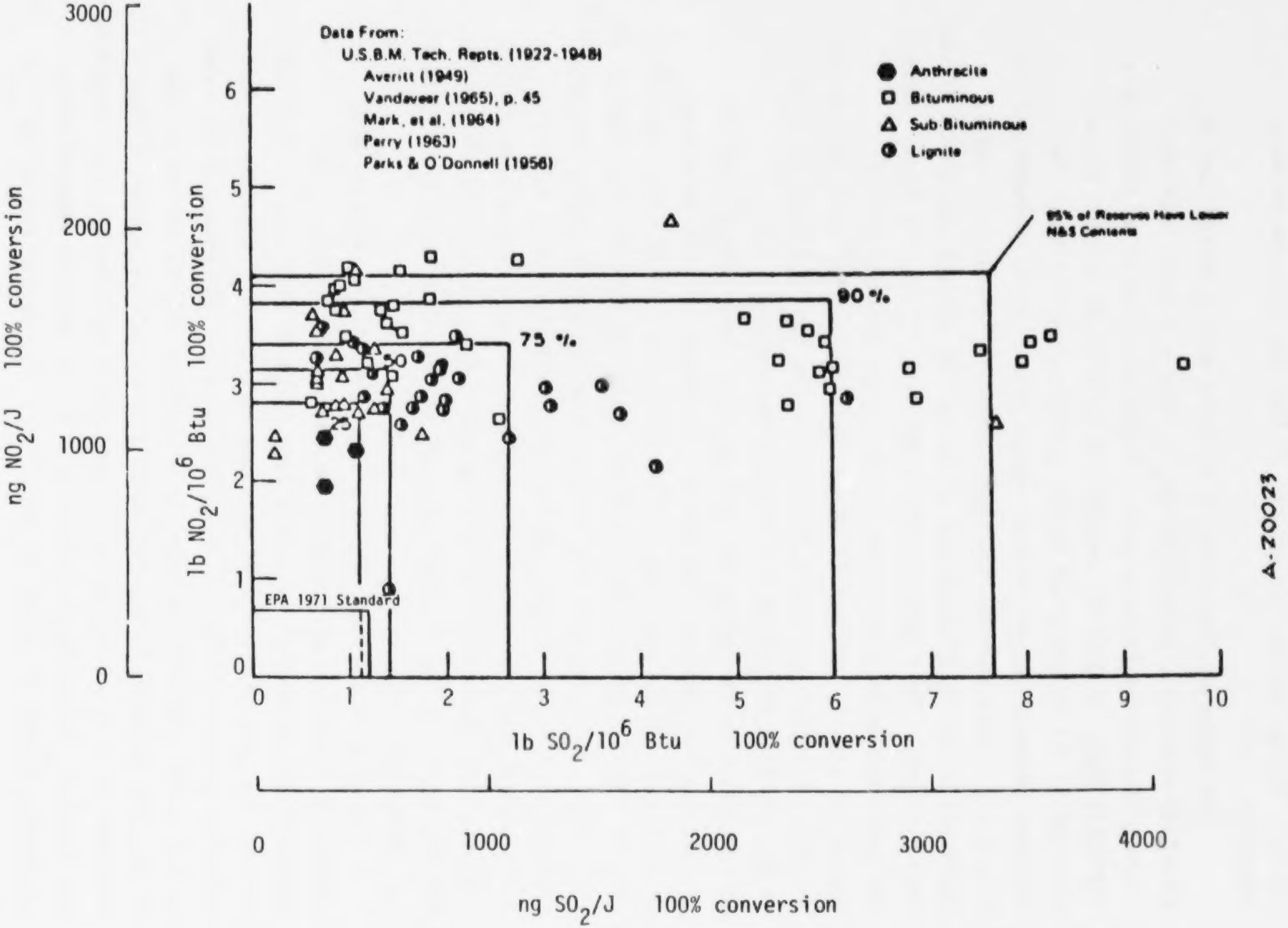

Figure 2-1. Nitrogen and sulfur content of U.S. coal reserves (Reference 2-12).

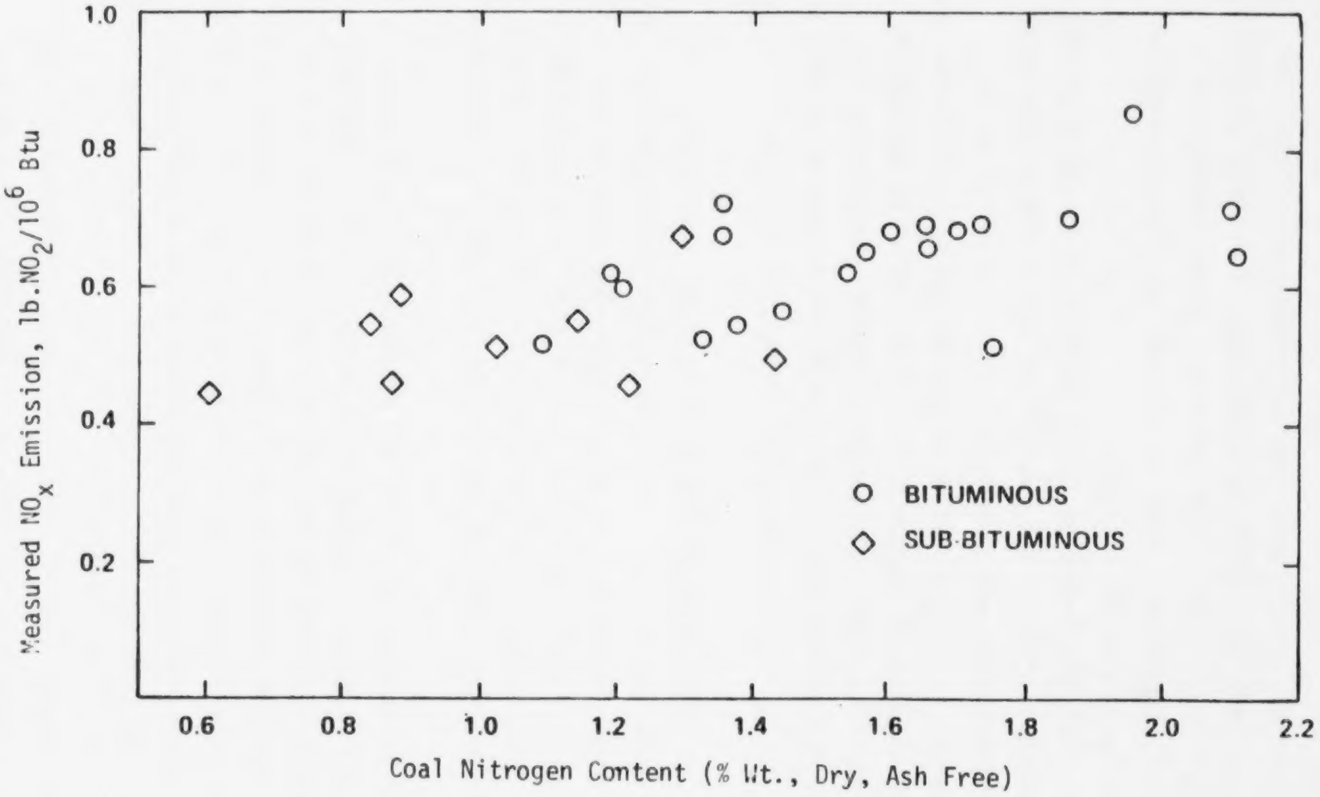

Figure 2-2. Nitric oxide emission as measured vs. coal nitrogen content (Reference 2-13).

industrial boilers by KVB under an EPA sponsored field test program indicated that no direct correlation between total NO_x emissions and coal fuel nitrogen, per se, exists (Reference 2-20). The tentative generalizations that can be made at this time are that the higher nitrogen fuels do produce more NO_x in the order coal, residual oil, distillate oil, natural gas, but within a given fuel category, e.g. coal, no definite conclusions can be drawn. Since field experience is not definitive, a review of the current fundamental theories of fuel NO_x formation may be profitable in developing control strategy.

In general, fuel NO_x formation is the product of oxidation of the nitrogen in the volatiles and in the char of the coal. The oxidation of char nitrogen to NO proceeds much more slowly than the oxidation of volatilized nitrogen. In fact, based on a combination of experimental and empirical modeling studies, it is now believed that 60 to 80 percent of the fuel NO_x results from volatile nitrogen oxidation (References 2-11 and 2-14). Conversion of the char nitrogen to NO is in general lower, by factors of two to three, than conversion of total coal nitrogen (Reference 2-15).

Regardless of the precise mechanism of fuel NO_x formation, several general trends are evident, particularly for coal combustion. As expected, fuel nitrogen conversion to NO is highly dependent on the fuel/air ratio for the range existing in typical combustion equipment (Reference 2-16). This behavior is due largely to volatile NO formation, while oxidation of the char nitrogen is relatively insensitive to fuel/air changes.

In contrast to thermal NO_x, fuel NO_x production is relatively insensitive to small changes in combustion zone temperature (Reference 2-15). Char nitrogen oxidation appears to be a very weak function of temperature, and although the amount of nitrogen volatiles appears to increase as temperature increases, this is believed to be partially offset by a decrease in percentage conversion (Reference 2-15). Furthermore, operating restrictions severely limit the magnitude of actual temperature changes attainable in current systems.

As described above, fuel NO_x emissions are a strong function of fuel/air mixing. In general, any change which increases the mixing between the fuel and air during coal devolatilization will dramatically increase volatile nitrogen conversion and increase fuel NO. In contrast, char NO formation is only weakly dependent on initial mixing and therefore may represent a lower limit on the emission level which can be achieved through burner modifications (Reference 2-10).

In principle, the best strategy for fuel NO_x abatement combines low excess air firing, optimum burner design, and staged combustion. Assuming suitable stage separation, low excess air (LEA) may have little effect on fuel NO, but it increases system efficiency. Before using LEA firing, the need to get good carbon burnout and low CO emissions must be considered.

Optimum burner design ensures locally fuel-rich conditions during devolatilization, which promotes reduction of volatilized nitrogen compounds to N_2. Staged combustion produces overall fuel-rich conditions during the first 1 to 2 seconds and promotes the reduction of NO to N_2 through reburning reactions. High secondary air preheat also appears desirable, because it promotes more complete nitrogen volatilization in the fuel-rich initial combustion stage. This leaves less char nitrogen to be subsequently oxidized in the fuel-lean second stage. Unfortunately, it also tends to favor thermal NO formation, and at present there is no general agreement on which effect dominates (Reference 2-10).

2.1.3 Principles of Control

In summary of the above discussion, both thermal and fuel NO_x are far below the levels which would prevail at equilibrium at peak temperature. Thus, the rate of formation of both thermal and fuel NO_x is dominated by combustion conditions and is amenable to suppression through combustion process modifications. Although the mechanisms are different, both thermal and fuel NO_x are promoted by rapid mixing of oxygen with the fuel. Additionally, thermal NO_x is greatly increased by increased residence time at high temperature. The modified combustion conditions and control concepts which have been tried or suggested to combat the formation mechanisms are as follows:

- Decrease primary flame zone O_2 level by:
  - -- Decreased overall O_2 level
  - -- Controlled mixing of fuel and air
  - -- Use of fuel-rich primary flame zone

- Decrease time of exposure at high temperature by:
  - -- Decreased peak temperature:
    - Decreased adiabatic flame temperature through dilution
    - Decreased combustion intensity
    - Increased flame cooling
    - Controlled mixing of fuel and air or use of fuel-rich primary flame zone
  - -- Decreased primary flame zone residence time
- Chemically reduce NO_x in post-flame region by:
  - -- Injection of reducing agent

Table 2-1 relates these control concepts to applicable combustion process modifications and equipment types. The process modification are further categorized according to their role in the control development sequence: operational adjustments, hardware modifications of existing equipment or through factor installed controls, and, major redesigns of new equipment. The controls for decreased O_2 are also generally effective for peak temperature reduction but have not been repeated.

Table 2-2 summarizes the availability and status of the primary controls shown in Table 2-1 as applicable to the major boiler fuel type categories identified earlier. The following subsections review the status and performance of each of these applicable controls.

2.2 COAL-FIRED BOILERS

Industrial coal-fired boilers are of both the pulverized and stoker types. Pulverized coal-fired boilers are usually limited to sizes greater than 29 MW heat input (100 x 10^6 Btu/hr) (Reference 2-17) and account for 3.9 percent of the total industrial boiler population (Reference 2-2). Stokers, instead, range from less than 0.3 MW to 120 MW of heat input (1 to 400 x 10^6 Btu/hr) and account for 11.25 percent of the total industrial boiler population (Reference 2-2).

Two basic designs exist for industrial boilers burning pulverized coal: single wall and tangential. However, cyclone boilers are often included in this fuel type category even through the coal they burn is not pulverized but crushed.

As already discussed in Subsection 2.1 on NO_x formation mechanisms, and will be further elaborated in this subsection as well as Section 3, there are insufficient emissions data on coal-fired industrial

TABLE 2-1. SUMMARY OF COMBUSTION PROCESS MODIFICATION CONCEPTS (REFERENCE 2-10)

Combustion Conditions	Control Concept	Effect on Thermal NO_x	Effect on Fuel NO_x	Primary Alplicable Controls		
				Operational Adjustments	Hardware Modification	Major Redesign
Decrease primary flame zone O_2 level	Decrease overall O_2 level	Reduces O_2 rich, high NO_x pockets in the flame	Reduces exposure of fuel nitrogen intermediaries to O_2	Low excess air firing	Flue gas recirculation (FGR)	
	Delayed mixing of fuel and air	Flame cooling and dilution during delayed mixing reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burner adjustments	Low NO_x burners	Optimum burner/ firebox design
	Primary fuel-rich flame zone	Flame cooling in low O_2, low temp. primary zone reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burners out of service; biased burner firing	Overfire air ports	Burner/firebox design for two stage combustion
Decrease peak flame temperature	Decrease adiabatic flame temperature	Direct suppression of thermal NO_x mechanism	Ineffective	Reduced air preheat	Water injection, FGR	
	Decrease combustion intensity	Increased flame zone cooling yields lower peak temperature	Minor direct effect; indirect effect on mixing	Load reduction		Enlarged firebox, increased burner spacing
	Increased flame zone cooling/ reduce residence time	Increased flame zone cooling yields lower peak temperature	Ineffective	Burner tilt		Redesign heat transfer surfaces, firebox aerodynamics
Chemically reduce NO_x in post flame region	Inject reducing agent	Decomposition	Decomposition		Ammonia injection possible on some units	Redesign convective section for NH_3 injection

T-1836

TABLE 2-2. APPLICABILITY OF COMBUSTION MODIFICATION NO$_x$ CONTROLS FOR MAJOR INDUSTRIAL BOILER EQUIPMENT/FUEL TYPES

Fuel	Coal		Oil and Natural Gas		
	Equipment Type				
Combustion Modification	Packaged and Field Erected Stokers	Field Erected Pulverized Coal	Field Erected Watertube	Packaged Watertube	Packaged Firetube
Low Excess Air (LEA)	Available but not implemented[a]	Available, implemented on limited basis	Available, implemented on limited basis	Available but not implemented	Available but not implemented
Load Reduction (LR)	Available but not implemented	Available but not implemented	Available but not implemented	Available but not implemented	Available but not implemented
Staged Combustion with Overfire Air Injection (OFA)	Available but not implemented	Implemented on limited basis	Available but not implemented	Not available R&D[b] status	Not available R&D[b] status
Staged Combustion with Burners out of Service (BOOS)[c]	Not applicable	Available but not implemented	Available but not implemented	Not applicable for single burner boilers	Not applicable
Flue gas Recirculation (FGR)	Not applicable	Not available. limited research	Available	Available	Available
Low NO$_x$ Burners (LNB)	Not applicable	Not available. R&D[b] status	Commercially offered but not demonstrated	Commercially offered but not demonstrated	Commercially offered but not demonstrated
Ammonia Injection	Not available. Limited research	Commercially offered but not demonstrated	Commercially offered but not demonstrated	Commercially offered but not demonstrated	Commercially offered but not demonstrated
Reduced Air Preheat (RAP)	Not available. Limited research	Not available. Fuel penalty too high	Available	Available	Not applicable
New Furnace Design (Decreased Heat Release Rate)	Not available. Limited research	Available but not implemented	Not available. Limited research	Not available. Limited research	Not available. Limited research

T-1746

[a] Means that control technique is commercially available, but is not presently being implemented for emission control.

[b] R&D, Research and Development.

[c] BOOS is considered a retrofit NO$_x$ control measure.

boilers to warrant a breakdown of baseline or achievable control levels based on coal type. The few boiler and coal types tested are not adequate to establish the significance of any trends. In fact, as discussed earlier, some of the so-called data trends are conflicting. Variations in emissions from boiler to boiler (of the same firing type, etc.) are often greater than possible variations due to coal type (see, for example, Table 7-2).

Of the four single wall pulverized coal-fired boilers analyzed, three showed baseline (normal operation) emissions of 174, 216 and 244 ng/J (0.405, 0.502, and 0.567 lb/10^6 Btu) as NO_2 and the fourth showed baseline emissions of 563 ng/J (1.31 lb/10^6 Btu) as NO_2 (References 2-18 and 2-19).* These boilers ranged in size from 46.7 to 117 MW (160 to 400 x 10^6 Btu/hr) with the fourth boiler having an input capacity of 76.2 MW (260 x 10^6 Btu/hr). The large baseline emissions of the fourth unit could not be explained by any significant differences in fuel properties, boiler characteristics, or operating conditions. One cyclone boiler tested emitted 494 ng/J (1.15 lb/10^6 Btu) as NO_2 at baseline (References 2-18 and 2-20). Cyclone boilers are generally large NO_x producers; thus these high NO_x levels are not surprising. A 66 MW (225 x 10^6 Btu/hr) and a 94 MW (320 x 10^6 Btu/hr) tangential coal-fired boiler were also tested. Baseline emissions were 234 and 296 ng/J (0.544 and 0.688 lb/10^6 Btu) as NO_2, respectively (Reference 2-18). Because of the small number of boilers tested and the small difference in the average NO_x emissions from tangential and single wall industrial boilers, their NO_x emissions will be averaged together in this study.

Emission data from industrial boilers burning pulverized coal are limited to the six units above. However, large industrial boilers are similar in design to utility boilers. Based on this similarity in design, a direct comparison of NO_x emissions can be made. Control techniques applicable to utility boilers can often be applied to large industrial boilers.

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*Note: NO_x emission data discussed in this report are all listed in Section 7 along with boiler and fuel characteristics.

Stokers are classified according to the method of feeding fuel to the furnace (Reference 2-17). The four major types are:

- Spreader
- Underfeed
- Chain grate or traveling grate
- Vibrating grate

The type of stoker used in a given application is usually dependent on the type of coal burned and the response time required for load changes. For example underfeed stokers are best equipped to burn caking coals and spreader stokers most easily follow fluctuating loads.

Generally stokers emit lower uncontrolled NO_x emissions than pulverized coal-fired boilers. Reported baseline NO_x emissions vary from 153 to 336 ng/J (0.356 to 0.781 lb/10^6 Btu) as NO_2 for spreader stokers, 136 to 163 ng/J (0.317 to 0.379 lb/10^6 Btu) as NO_2 for underfeed stokers and 100 ng/J to 178 ng/J (0.233 to 0.414 ng/J) as NO_2 for chain grate stokers (Reference 2-18 through 2-21).

The following subsections summarize the NO_x control techniques via combustion modifications for these two major coal-fired industrial boiler types: pulverized coal and stokers.

2.2.1 Applicable Control Techniques for Pulverized Coal-Fired Boilers

Field test data on combustion modifications to reduce NO_x emissions from industrial boilers firing pulverized coal are very limited. However, due to the basic similarity in equipment design between the industrial and utility size boilers, applicable combustion modifications estalbished for the smaller utility steam generators are also applicable for the larger industrial size units. Added limitations are present though when implementing these controls on the smaller boilers. These limitations are discussed for each of the control techniques.

Table 2-3 lists the combustion modifications which are applicable to pulverized coal-fired boilers. Combustion modifications for which no actual data exist for the industrial boiler size range have also been included. The effectiveness and limitations of these individual techniques are based on data reported for utility size boilers. The information on the number of industrial size boilers tested clearly shows that the data on control techniques for these units are indeed very

TABLE 2-3. COMBUSTION MODIFICATION NO_x CONTROLS FOR PULVERIZED COAL-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commercial Availability/ R&D Status	Comments
Low Excess Air (LEA)	Reduction of combustion air.	6	0-25 (avg. 8.9)	Excess oxygen reduced to 5.2% on the average	Available	Added benefits of technique include increase in boiler efficiency, limited by increase in CO. HC and smoke emissions.
Burners Out of Service (BOOS)	One or more burners on air only. Remainder firing fuel rich.	2	27-39 (avg. 33)	Applicable only for boilers with minimum of 4 burners.	Available. However, extensive engineering work necessary prior to implementation.	Limited by the number of burners available. Load reduction required in most cases. Possible increased slagging, corrosion.
Overfire Air Injection (OFA)	Secondary air from OFA ports above fuel rich firing burners		5-30	Burner stoichiometry as low as 100%	Commercially offered but not demonstrated for industrial size boilers.	Requires installation of OFA ports, etc. Possible increased slagging, corrosion.
Flue Gas Recirculation	Recirculation of flue gas to burner windbox		0-20	Up to 25% of the flue gas recirculated.	Not offered because relatively ineffective.	Requires installation of FGR ducts, fan, etc. Can cause combustion instability. Burner windbox may need extensive modifications.
Low NO_x Burners (LNB)	New burner designed utilizing controlled air-fuel mixing		45-60	Prototype LNB limited to size ranges above 100 MBtu/hr	Still in the development stage. Prototype LNB available from major boiler mfrs.	Active R&D efforts underway.
Ammonia Injection	Injection of NH_3 in convective section of boiler.		40-60	Limited by furnace geometry. NH_3 injection rate limited to 1.5 NH_3/NO	Commercially offered but not demonstrated	Probably best suited as a new design feature than a retrofit application. Possible implementation and operational problems.
Reduced Load	Reduction of fuel and air flow to the boiler.		Varies from 45% reduction to 4% increase in NO_x	Applicable to all boilers. Load can be reduced to 25% of capacity.	Available now but not implemented because of adverse operational impacts	Load reduction not effective because of increase in excess O_2. Best implemented with increase in furnace size for new boilers.

T-1747

limited. In fact, the boilers that were tested were only tested for a short period of time (generally <3 hours).

2.2.1.1 Low Excess Air

Reducing the excess air level in the furnace has generally been found to be an effective method for NO_x control. In this technique, the combustion air is reduced to the minimum amount required for complete combustion, while maintaining acceptable furnace cleanliness, and steam temperature. With less oxygen available in the flame zone, both thermal and fuel NO_x formation are reduced. In addition, the reduced airflow lowers the quantity of flue gas released resulting in an improvement in boiler efficiency.

Low excess air operation is a relatively simple technique to implement. It is applicable to all boiler types and requires only reducing airflow to the burner windbox. However, in a multiburner unit, modifications to the windbox might be necessary to improve air distribution to individual burners during low excess air operation. Lowering excess air reduces the safety margin for complete combustion. Therefore, close monitoring of flue gas O_2 and CO may be necessary.

Baseline excess oxygen levels for single wall and tangential pulverized coal-fired boilers investigated ranged from 4.5 to 8.6 percent and averaged 6.3 percent (References 2-18 and 2-19). In these boilers excess oxygen was reduced to 5.2 percent lowering NO_x emission by 8.6 percent on the average.

The lone cyclone boiler (117 MW, 400 x 10^6 Btu/hr) tested was the least amenable to excess oxygen reduction because of the initial low baseline O_2 level. The excess oxygen measured 3.4 percent at baseline and was reduced only to 3.1 percent for LEA firing. NO_x emissions were reduced 5 percent for this test (References 2-4 and 2-18).

These excess oxygen levels were probably not representative of the actual excess oxygen in the flue gas leaving the furnace. Air infiltration into the boiler ducts for balanced draft boilers can dilute the flue gas and cause oxygen readings to be higher than actual. However, field investigations found that these units were, in general, being fired with more than adequate excess air in order to assume complete combustion and provide a margin of safety.

Combustion with low excess air is a favorite NO_x control technique because it not only reduces NO_x by 25 ppm on the average for each percent reduction in excess oxygen, but it also increases boiler efficiency and furthermore is relatively easy to implement.

2.2.1.2 Overfire Air Injection (OFA)

The injection of air above the top burner level through OFA ports together with a reduction in air flow to the burners is one of two techniques used to obtain staged combustion in industrial size pulverized coal-fired boilers. The other technique, burners out of service, is discussed below in Section 2.2.1.3.

New utility tangential coal-fired boilers currently come equipped with overfire air ports to help meet 1971 NSPS for NO_x emissions. Overfire air ports on wall-fired boilers are not as common as for the tangentially fired units. However, Babcock and Wilcox (B&W) has recently installed two 190 MW (650 x 10^6 Btu/hr) pulverized coal-fired industrial boilers equipped with OFA ports and compartmented windboxes to limit NO_x emissions to 300 ng/J (0.7 lb/10^6 Btu) (References 2-22 and 2-23). In these boilers, 105 percent of the total air requirement is added to the burners, 10 percent through the OFA ports. Automatic controls determine the difference between the total air requirements for the total fuel flow to the furnace and the total air flow to the individual burner compartments. This difference in air flow is then fed through the OFA ports.

The combination of the compartmented windbox and careful airflow control also improves the thermal efficiency of these new B&W units. B&W provides oxygen analyzers on all new coal-fired industrial boilers. Overfire air cannot be implemented on cyclone boilers because the cyclone furnace cannot be fired substoichiometrically.

No detailed OFA test data have been reported for pulverized coal-fired industrial boilers. Therefore the information listed in Table 2-3 reflects results from utility boiler data (Reference 2-24). Overfire air has been very effective in reducing NO_x for boilers of this size. In fact, 30 percent reductions have been reported for utility boilers of the tangential firing type. Potential limitations of the technique include (References 2-25 and 2-26):

- Furnace tube wastage due to local reducing conditions when firing high sulfur coal
- Tendency for slag accumulation in the furnace
- Additional excess air may be required to ensure complete combustion resulting in a decrease in boiler efficiency.

Experience with utility boilers indicates, however, that these potential problems can be overcome with proper implementation of staged combustion (Reference 2-24.)

Overfire air is more attractive in original designs than in retrofit applications. Additional duct work, furnace penetration, and extra fan capacity may be required. In addition, physical obstructions outside of the boiler may make retrofit installation difficult and costly. There may also be insufficient height between the top row of burners and the furnace exit to permit accommodation of overfire air ports and the enlarged combustion zone created by the staged combustion technique (Reference 2-25).

2.2.1.3 Burners Out of Service (BOOS)

Burners out of service is the other technique used to obtain staged combustion in industrial pulverized coal-fired boilers. It is primarily employed as a retrofit NO_x control measure for existing utility sized boilers. Ideally, all of the fuel flow is diverted from a selected number of burners to the remaining firing burners. Since airflow is maintained relatively unchanged among all burners a staged combustion effect is obtained. For the technique to be significantly effective the top burners must be set on air only. The technique, however, has several limitations for pulverized coal-fired boilers. These limitations can be summarized as follows:

1. Individual burners cannot be shut off because coal flow must be terminated at a pulverizer. Since each pulverizer serves a minimum of two burners, at least two burners must be removed from service.
2. Indiscriminate selection of burners out of service is often not possible because pulverizers may serve burners located on two separate levels

3. In many cases burners/pulverizers which operate during BOOS cannot handle increased coal flow necessitating a significant reduction in the boiler steam rating
4. Register adjustments are often necessary to divert some airflow from top burners to lower burners. If satisfactory staging conditions cannot be obtained simply by adjusting burner registers, a compartmental windbox becomes necessary.

These limitation were clearly evident in the tests conducted on one pulverized coal-fired industrial size boiler (76 MW heat input) equipped with 4 burners in square matrix (Reference 2-20). To implement the BOOS technique the pulverizer serving the top two burners was shut off necessitating a 50 percent reduction in boiler load. In addition, airflow could not be easily controlled to individual burners so that burner swirl and coal air mixing were affected. The resultant NO_x reduction was 39 percent.

From this experience, it is evident that to implement the BOOS technique with this burner pattern and the number of available burners necessitates a reduction in the capacity of the boiler by up to 50 percent. It is expected that this will often be the case for industrial boilers because of the limited number of burners and pulverizers.

Since a reduction in boiler load is not desirable and often not feasible, BOOS is not always a viable technique. A potential alternative involves the installation of overfire air ports above existing burners if there is space for the overfire air ports (already discussed in Section 2.2.1.2).

2.2.1.4 Low NO_x Burners (LNB)

Prototype low NO_x pulverized coal-fired burners have been developed primarily for reducing NO_x emissions from utility boilers. Their principal characteristics are reduced flame turbulance, delayed fuel air mixing, and establishment of fuel-rich zones where combustion initially takes place (Reference 2-24). Prototype dual register burners developed by Babcock and Wilcox (B&W) (References 2-27 and 2-28) and the dual throat burners developed by Foster Wheeler (FW) (References 2-29 and 2-30) are being installed in new utility size coal-fired boilers. This technology applies only to wall-fired boilers. NO_x reductions reported in Table 2-3 are based on results from B&W and FW utility application testing because no industrial size low NO_x coal burner has yet been developed.

Energy and Environmental Research Corporation (EER), under a research contract to EPA, is developing advanced low NO_x burner concepts such as distributed fuel/air mixing, as illustrated in Figure 2-3 (References 2-31 and 2-32). Field evaluation programs, also sponsored by EPA, involving several manufacturers and R&D groups, are being planned (Reference 2-79).

A low NO_x burner for industrial boiler application is under commercial development by Peabody Engineering Corporation. Peabody is constructing a variation of a standard dual register type burner. The 50 x 10^6 Btu/hr burner may become one of several burners to be tested in an EPA test program. Basically, the burner is designed to reduce the air in the primary combustion zone. The resultant reduced flame temperatures also serve to lower NO_x emissions. Once completed, the burner presumably will not be restricted in size range and may be suitable for many pulverized coal facilities (Reference 2-33).

In some applications low NO_x burners may have several advantages over other combustion modifications such as staged combustion with OFA or BOOS. For example, one utility boiler manufacturer claims that low NO_x burners will maintain the furnace in an oxidizing environment, hence, minimizing slagging and reducing the potential for furnace corrosion when firing high sulfur coal (Reference 2-27). Also, more complete carbon utilization may be achieved due to better coal/air mixing in the furnace. Finally, lower oxygen levels may be obtained with all the combustion air admitted through the burners (Reference 2-24).

Since the burners generally alter the flame configuration, care must be taken when applying the burners to existing boilers. For instance, the dual register coal burners have a longer flame length. The burner can be installed only in those boilers which are large enough to avoid cold wall impingement.

It is estimated that low NO_x burners will not be fully commercialized for the utility boilers for two more years. Its application for industrial size pulverized coal-fired steam generators is also a few years away.

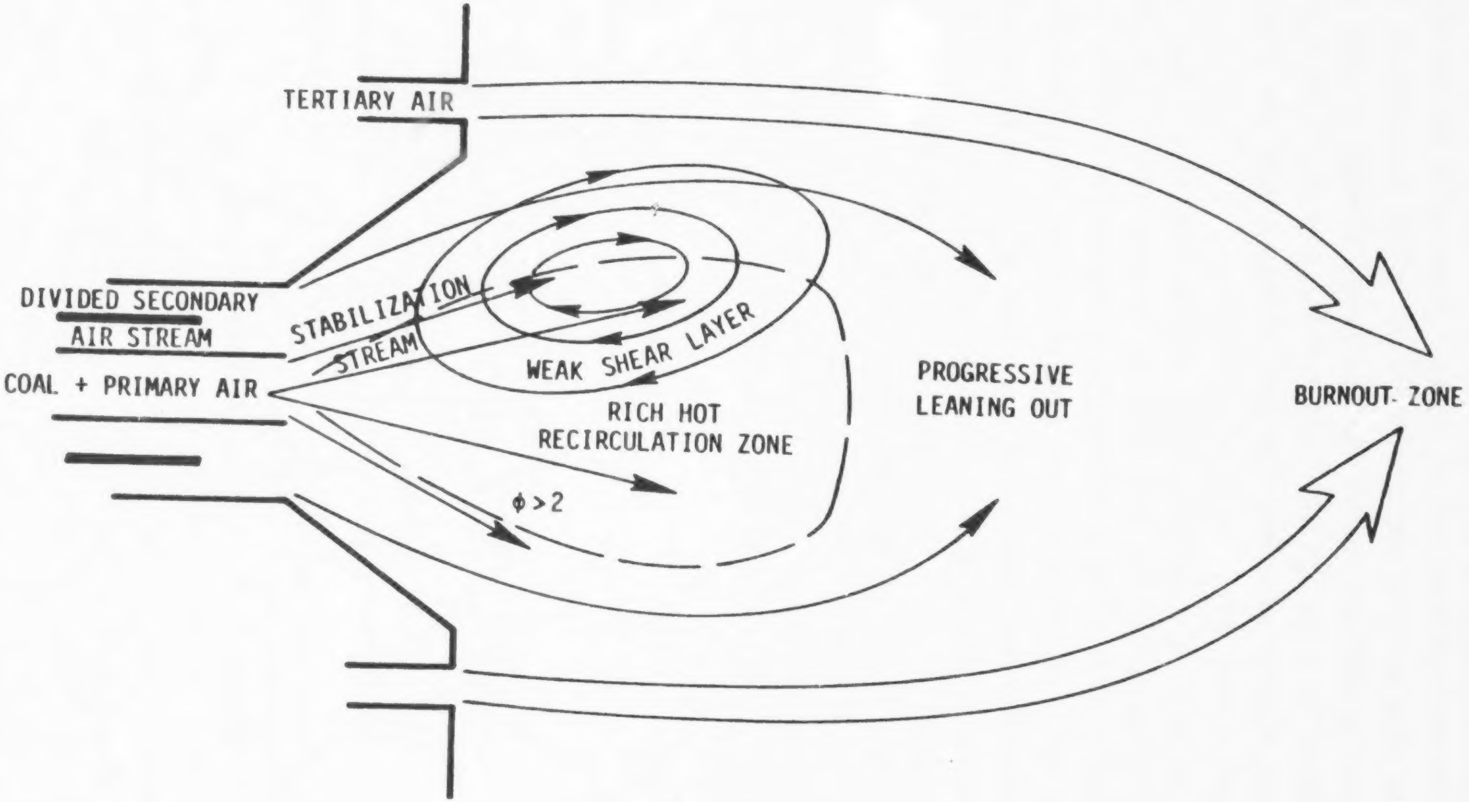


Figure 2-3. Distributed fuel/air mixing concept (Reference 2-31).

2.2.1.5 Flue Gas Recirculation (FGR)

Flue gas recirculation for NO_x control consists of extracting a portion of the flue gas from the economizer outlet and returning it to the furnace, admitting the flue gas through the burner windbox. Figure 2-4 shows a schematic of a typical FGR installation. Flue gas recirculation lowers the bulk furnace gas temperature and reduces oxygen concentration in the combustion zone (Reference 2-24).

Flue gas recirculation through the windbox and, to a lesser degree, through the furnace hopper has been found to be very effective for NO_x control on gas- and oil-fired utility boilers (References 2-26 and 2-34). However, the technique was relatively ineffective on coal-fired units because FGR mainly affects thermal NO_x, not fuel NO_x (Reference 2-35). Table 2-3 gives performance data on FGR with low excess air (LEA) on opposed wall coal-fired utility boiler. These data show that for this boiler, combined flue gas recirculation and low excess air can only reduce NO_x emissions by 20 percent (Reference 2-35). Similar results have been reported elsewhere (Reference 2-10). The technique of low excess air alone can often achieve similar reductions, as discussed earlier.

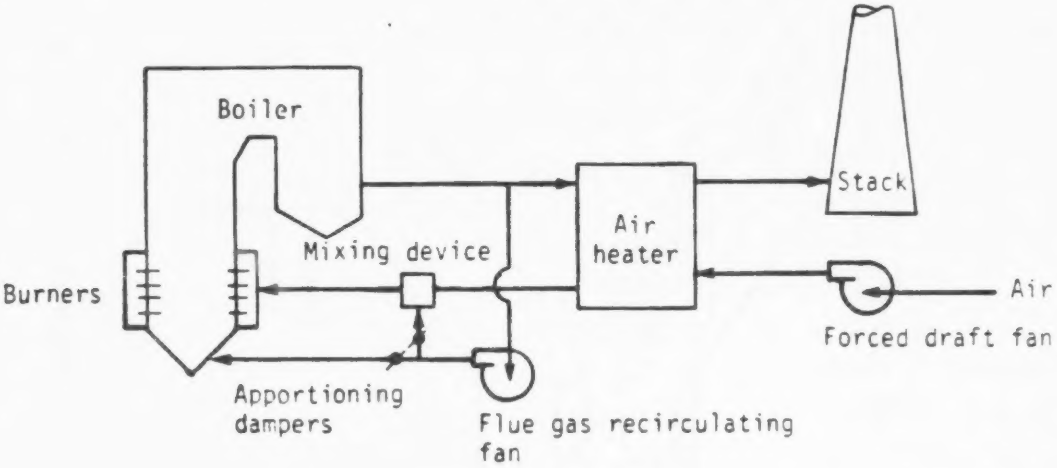


Figure 2-4. Typical flue gas recirculation system for NO_x control.

No data are available for pulverized coal-fired industrial units but as large industrial boilers are similar in design to utility boilers, performance of FGR is not expected to vary greatly from this result.

Flue gas recirculation for NO_x control is less costly for new designs than as a retrofit application. Retrofit installation of flue gas recirculation can be quite costly. The fan, ductwork, dampers, and controls as well as possibly having to increase existing fan capacity due to increased draft loss, can represent a large investment. In addition, the flue gas recirculation system itself may require a substantial maintenance program due to the high temperature environment experienced and potential erosion from entrained ash. Thus, the cost effectiveness of this method of NO_x control for pulverized coal-fired boilers has to be examined carefully when comparing it to other control techniques.

As a new design feature, the furnace and convective surfaces can be sized for the increase in mass flow and change in furnace temperatures. In retrofit applications, however, the increased mass flow increases turbulence and mixing in the burner zone, and alters the convective section heat absorption. Erosion and vibration problems may result (References 2-34 and 2-74) and flame detection can be difficult. In addition, controls must be employed to regulate the proportion of flue gas to air so that sufficient concentration of oxygen is available for combustion (Reference 2-75). In summary, the relatively small NO_x reductions obtained with FGR when firing coal may not warrant the large investment for both a retrofit case or installation of FGR on new industrial units.

2.2.1.6 Ammonia Injection

The process of injecting ammonia in the hot flue gas to reduce NO_x emissions has been patented under the trade name Thermal $DeNO_x$ by Exxon Research and Engineering Company (Reference 2-36). Experimental data have shown that NH_3 injection under well controlled laboratory conditions, can result in NO_x reductions as high as 90 percent (Reference 2-37). Figure 2-5 (Reference 2-38) shows a schematic of a retrofit application of a Thermal $DeNO_x$ injection system on a large industrial size boiler. The technique acts by reducing NO to elemental nitrogen and oxygen with NH_3 at flue gas temperatures ranging from

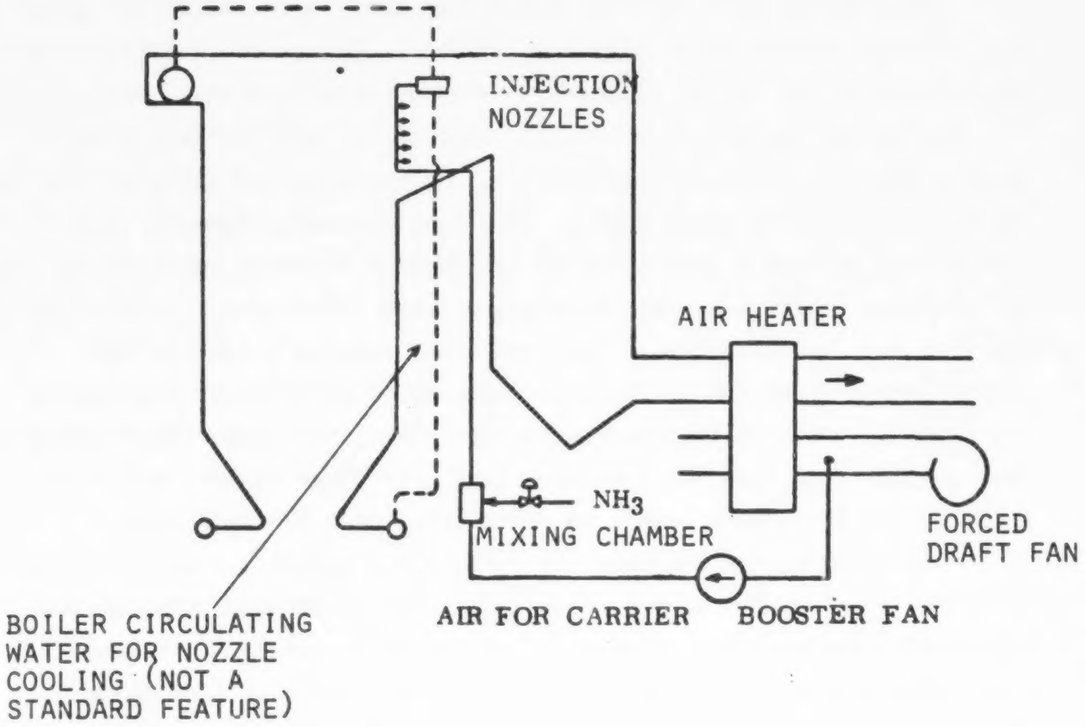


Figure 2-5. Schematic diagram of the NH_3 injection system (Reference 2-38).

approximately 1070 to 1290K (1470 to 1856°F). However, optimal NO reduction occurs over a very narrow temperature range, around 1240 ± 50K (1770 ± 90°F).

The NO_x reduction effectiveness reported in Table 2-3 reflects results from full-scale application of the ammonia injection process in gas- and oil-fired industrial boilers in Japan (Reference 2-39). No full- scale retrofit on a coal-fired unit has been accomplished so far. However, in subscale tests it was found that the flue gas environment from coal combustion does not markedly affect the effectiveness of the process any more than that relative to gas and oil combustion products (Reference 2-40).

Ammonia injection has numerous limitations which have so far prevented its full-scale commericalization as a NO_x reduction technique on coal-fired boilers. These limitations can be summarized as follows: (References 2-37, 2-39 and 2-41).

- Performance is very sensitive to flue gas temperature, and is maximized only within a 50K temperature gradient from the optimum temperature of about 1240K. This temperature sensitivity may require special procedures for load following boilers.
- Performance is very sensitive to flue gas residence time at optimum temperatures. High flue gas quench rates are expected to reduce process performance.
- Costs of the process can be much higher than for other combustion controls
- Successful retrofit application is highly dependent on the geometry of convective section
- Byproduct emissions such as ammonium bisulfate might cause operational problems, especially in coal-fired boilers

Although NH_3 injection is currently being commercially offered, it is not demonstrated technology. Therefore, it should be considered to be still at the development stage (Reference 2-76). This technique might prove to be, however, the only alternative in controlling NO_x emission from cyclone-fired boilers which are not amenable to other combustion modifications. Therefore, its use can potentially achieve NO_x emission levels which would otherwise not be obtainable with current state-of-the-art controls (Reference 2-39).

2.2.1.7 Load Reduction

Thermal NO_x formation generally increases as the volumetric heat release rate or combustion intensity increases (Reference 2-10). Reduced combustion intensity can be brought about by load reduction, or derating, in existing units and by use of an enlarged firebox in new units.

However, during field tests on industrial boilers burning pulverized coal, NO_x emissions were found to increase in some instances when these boilers were operated below 60 percent of capacity (Reference 2-20). A load reduction of approximately 30 percent from the baseline rating of 80 percent capacity increased NO_x emissions from three boilers by 13 percent on the average. The reduced heat input was accompanied in all cases by an increase in excess oxygen averaging 0.7 percent. One cyclone units, however, showed a drop in NO_x emissions by 6 percent for a load reduction of 25 percent (Reference 2-4). Thus, it seems that in many cases any beneficial effects resulting from load reduction were offset by the increase in excess air required at the reduced load.

Reduced firing rate often leads to several operating problems. Aside from the limiting of capacity, low load operation usually requires higher levels of excess air to maintain steam temperature and to control smoke and CO emissions. The steam temperature control range is also reduced substantialy for those industrial boilers producing superheated steam. This will reduce the operating flexibility of the unit and its response to changes in load. The combined results are reduced operating efficiency due to higher excess air and reduced load following capability due to a reduction in control range (Reference 2-10).

When the unit is designed for a reduced heat release rate, the problems associated with derating are largely avoided. The use of an enlarged firebox produces NO_x reductions similar to load reduction on existing units. This technique of larger firebox has been implemented on new coal-fired utility boilers since about 1970 (Reference 2-24). Generally, the size of these fireboxes has increased 30 percent partly in response to 1971 NSPS for utility boilers and partly to facilitate combustion of lower grade coals (Reference 2-42). Therefore, the technique can also be considered available for large industrial size pulverized coal-fired boilers. Babcock and Wilcox (B&W) is currently considering power furnace loading as one of several techniques for reducing NO_x emissions from their industrial boilers (Reference 2-43).

2.2.2 Applicable Control Techniques for Stokers

NO_x emissions from stokers are significantly lower than those from pulverized coal. These lower emissions have been attributed to the lower combustion intensity and to the partial staged combustion that naturally occurs during combustion on fuel beds (Reference 2-17).

Four methods have been used to modify the combustion of a stoker in order to reduce NO_x emissions. These methods are (1) reduced undergrate air or low excess air, (2) overfire air, (3) reduced air preheat, and (4) reduced heat input (References 2-4, 2-18, 2-19 and 2-21). Ammonia injection is potentially applicable although it has not yet been demonstrated on an industrial stoker. The boiler geometry and the flue gas temperature profile in a stoker should permit the implementation of the NH_3 injection process in a similar manner as for a pulverized coal-fired unit. Table 2-4 lists information on the performance and limitation of each of these techniques.

The information is based on limited data. A search for additional data from boiler manufacturers and researchers has not revealed any other applicable combustion modification for NO_x control for stokers (References 2-44 through 2-48).

2.2.2.1 Low Excess Air (LEA)

Figure 2-6 is a schematic of a spreader stoker furnace showing where combustion air is introduced in this type of boiler. Overfire air is generally controlled independently from undergrate air. Low excess air tests performed in the field consisted of reducing the undergrate airflow while maintaining the OFA flow approximately as in normal operation.

Recently EPA field tests of 17 stokers indicate that the excess oxygen levels at baseline operating conditions averaged about 9 percent (References 2-4, 2-18 through 2-21). During low excess air tests, the average excess oxygen level was reduced to 6.4 percent. Such reduction lowered NO_x emission levels approximately 10 percent for each 1 percent reduction in excess oxygen (Reference 2-4, 2-20, 2-21, 2-48, and 2-49).

The minimum achievable excess air is limited by several factors. Except for the water-cooled vibrating grate, the only cooling of the grate is by the flow of air past it. If this air is cut back too much, the grate can overheat. There is also the danger of creating local reducing zones as the air is cut back and forming harmful corrosion products. Another problem noticed during field tests has been the formation of clinkers as the excess oxygen was reduced, the CO emissions tend to rise. However, test results indicate that if excess oxygen levels are maintained above 5 percent, CO emissions will tend to stay below 150 ppm (Reference 2-18, 2-20 2-21 and 2-49). Limited data show CO emissions for underfeed stokers to be less sensitive to excess air levels than for spreader stokers (References 2-4, 2-18 and 2-20).

Fuel combustion with lowest possible levels of excess air assures maximum boiler efficiency unless the air is decreased to the point where unburned carbon losses are greatly increased. From the limited amount of data it can be tentatively generalized that if the airflow is maintained

TABLE 2-4. COMBUSTION MODIFICATION NO_x CONTROLS FOR STOKER COAL-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commerical Availability/ R&D Status	Comments
Low Excess Air (LEA)	Reduction of air flow under stoker bed.	15	5-25	Excess O_2 limited to 5-6% minimum	Available now but need R&D on lower limit of excess air.	Danger of overheating grate, clinker formation, corrosion, and high CO emissions.
Staged Combustion (LEA + OFA)	Reduction of under grate air flow and increase of overfire air flow.	5	5-25	Excess O_2 limited 5% minimum.	Most stokers have OFA ports as smoke control devices but may need better air flow control devices.	Need research to determine optimal location and orientation of OFA ports for NO_x emission control. Overheating grate, corrosion and high CO emission can occur if under grate air flow is reduced below acceptable level as in LEA.
Reduced Load	Reduction of coal and air feed to the stoker.	13	Varies from 49% decrease to 25% increase in NO_x (average 15% decrease)	Has been used down to 25% load.	Available	Only for stokers that can reduce load without increasing excess air. Not a desirable technique because of loss in boiler efficiency.
Reduced Air Preheat (RAP)	Reduction of combustion air temperature	1	8	Combustion air temperature reduced from 473K to 453K.	Available now if boiler has combustion air heater.	Not a desirable technique because of loss in boiler efficiency.
Ammonia Injection	Injection of NH_3 in convective section of boiler.		40-60 (from gas- and oil-fired boiler experience).	Limited by furnace geometry. Feasible NH_3 injection rate limited to 1.5 NH_3/NO	Not available. Needs investigation of full scale application.	Probably best suited as a new design feature than a retrofit application. Possible implementation and operational problems

T-1748

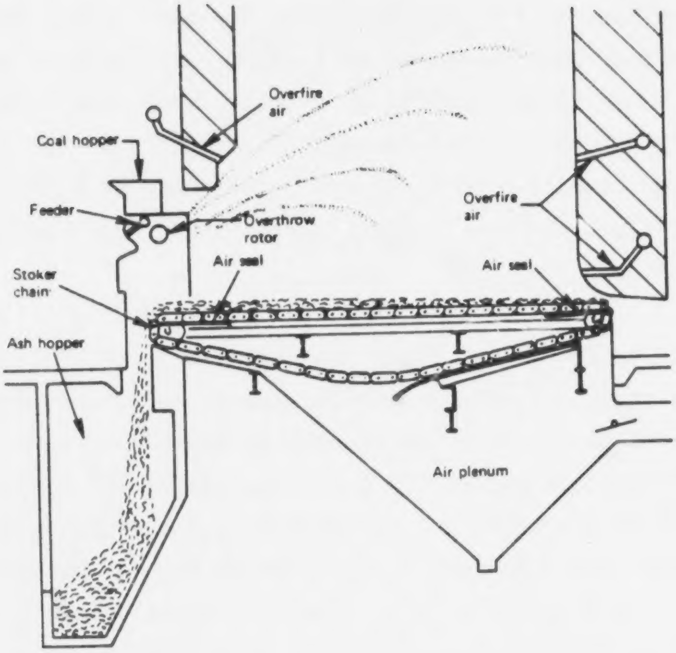


Figure 2-6. Air injection in a traveling-grade spreader stoker (Reference 2-17).

such that the excess oxygen level measures approximately 6 percent, no serious optional or emission problem should result. Of course, this generalization would require verification. Indeed, the minimum excess oxygen level for a particular boiler could be higher than 6 percent. NO_x emission reductions of about 5-25 percent and increases in boiler efficiency of one percent can be expected with LEA provided fuel burnout does not change during the process (References 2-4 and 2-20).

Research and developmental work on redesigning the grate and stoker would be necessary if lower excess oxygen levels are required. In addition a solution to the clinker formation problem will also be needed for this type of operation.

2.2.2.2 Staged Combustion

One of the reasons NO_x emission from stokers is lower than those from pulverized coal-fired boilers is the partial staged combustion nature of combustion of fuel beds (Reference 2-50). Volatile matter leaves the fuel bed as the coal is fed into the grate and burns above the bed level. The solids are subsequently burned with lower combustion intensity.

An increased staged combustion effect beyond what seems to occur naturally in the stoker furnace seems difficult to obtain. However, augmented staged combustion control can be effected by injecting air above the fuel bed through the overfire air ports (OFA) and reducing the undergrate airflow.

Figure 2-6 shows the relative location of these airflows. A reduction of 10 to 25 percent in NO_x has been achieved by this method without increasing CO emission (References 2-4, 2-18, 2-20 and 2-49). Most stokers have OFA ports as smoke control devices. Therefore, the location or orientation of the OFA ports may not be the optimum in order to achieve best NO_x reductions. For example, one test showed a 25 percent reduction in NO_x emissions by using two oil burners as overfire air ports (Reference 2-4). However, these burner ports were located far above the existing stoker OFA ports. Other OFA tests, using only the existing OFA ports located closer to the fuel bed rather than the burner ports, lowered NO_x emission only 10 percent.

This method suffers from the same disadvantages of LEA because reduced undergrate airflow is absolutely necessary to achieve any staging effect. Therefore limitations applicable to the technique of LEA such as grate overheating, corrosion, and clinker formation can also limit the application of the staged combustion technique.

2.2.2.3 Reduced Load

Underfeed stokers tend to produce lower NO_x emissions than spreader stokers. One reason has been attributed to the fact that underfeed stokers generally have larger fireboxes and consequently lower volumetric and surface heat release rates (References 2-4 and 2-20). Reducing the boiler load will lower the volumetric and surface heat release rate; therefore it is equivalent to having a larger firebox. One test on a spreader stoker shows a 10 percent reduction in NO_x emission by reducing the load from 70 to 60 percent of maximum continuous rating (References 2-18 and 2-20). On most other tests as the load was reduced, the excess air had to be increased, causing a net rise in NO_x emissions. These results suggest that the technique will be effective in reducing NO_x emissions only if the excess air can be maintained at the original level measured during the higher load condition.

The technique, although an applicable one, has numerous possible disadvantages. These include derating of the boiler and loss in boiler efficiency as a consequence of the requirements to increase the excess air level (Reference 2-20).

2.2.2.4 Reduced Air Preheat (RAP)

There is only limited data on reduced air preheat applied to industrial stokers. Based on tests on only one boiler, a small reduction of the combustion air temperature from approximately 366 to 355K (200^oF to 180^oF) reduced NO_x emissions by an average of 8 percent (References 2-18 and 2-20). Some researchers claim that the coal bed preheats the air before the combustion occurs and thus defeats the purpose of the method (Reference 2-50). This technique is of course limited to stokers equipped with combustion air preheaters. Only larger (> 29 MW, 100×10^6 Btu/hr) stokers tend to have air preheaters. In addition, significant losses in boiler efficiencies will occur if flue gas temperatures leaving the stack are increased as a consequence of bypassing air preheaters. Economizers could be added to avoid efficiency losses.

2.2.2.5 Ammonia Injection

Ammonia injection should be applicable to stoker boilers as well as pulverized coal-fired units. However, the geometry of the ducting in the convective section is crucial. The ammonia injection ports must be located in that portion of the furnace where the flue gas temperature ranges from 1070 to 1290K (1470 to 1860^oF).

The information on ammonia injection listed in Table 2-4 is the same as that in Table 2-3. The performance of the ammonia injection process has not been investigated on stokers; therefore the potential NO_x reductions listed in Table 2-4 are based on reported results on gas- and oil-fired industrial boilers (References 2-39).

2.3 OIL-FIRED BOILERS

Oil-fired industrial boilers fall into two major categories: firetube and watertube. Firetube boilers can be further divided into Scotch, horizontal return, tubular and firebox designs. Watertube boilers are identified as either packaged or field-erected units. Packaged boilers, both watertube and firetube, are usually equipped with a single burner. Field-erected units are usually equipped with an array of burners and are generally of larger capacity than the packaged units.

Oil-fired firetube boilers are designed with a maximum of 9 MW heat input (30 x 10^6 Btu/hr). These boilers account for 7.2 percent of the total industrial boiler population (Reference 2-2). Industrial watertube boilers can be as large as utility boilers, however the packaged watertube units are usually limited to 73 MW (250 x 10^6 Btu/hr) of heat input (Reference 2-51). Oil-fired watertube boilers account for 35.3 percent of total industrial boiler population -- 8.7 percent are packaged units and 26.6 percent are field-erected boilers (Reference 2-2).

Table 2-5 lists the baseline NO_x emissions from oil-fired industrial boilers measured during an EPA test program (Reference 2-4 and 2-20). Regardless of the boiler type, it is evident that boilers burning residual oil produce more NO_x emissions than the ones firing distillate oil. Also for any particular class of boilers the range of NO_x emissions for residual oil is often wider than the range of emissions for distillate oil. The larger amount and variation of fuel nitrogen in the residual oil accounts for both these observations. Fuel analyses performed as a part of this test program showed that residual oil generally contained 0.10 to 1.0 percent fuel nitrogen while distillate oil contains less then 0.05 percent on the average (Reference 2-20).

Combustion modification NO_x control techniques for oil-fired boiler are as follows:

- Low excess air (LEA)
- Staged combustion air (SCA)
- Burners out of service (BOOS)
- Flue gas recirculation (FGR)
- Reduced air preheat (RAP)
- Load reduction (LR)
- Low NO_x burners (LNB)
- Ammonia injection

These techniques can be applied singly or in appropriate combination, especially for ammonia injection which can be implemented with any other combustion modification. Also, the BOOS technique can only be applied to multiburner units and is usually confined to retrofit applications. Table 2-6 summarizes the information on the performance, applicability and

TABLE 2-5. NO_x EMISSIONS AT BASELINE AND AT LOW EXCESS AIR FROM OIL-FIRED INDUSTRIAL BOILERS (REFERENCES 2-4, 2-20, 2-52 AND 2-53)

Equipment Type	No. Boilers Tested	Residual Oil				
		Baseline			Low Excess Air	
		02 %	NO_x Emissions ng/J[a]	NO_x Emissions lb/10^6 Btu[a]	02 %	NO_x Reductions %
Firetube	5	5.2	95.5 - 170 (115.0)	0.222 - 0.395 (0.275)	3.2	7
Watertube W/O Air Preheat	9	5.9	87.5 - 362 (190)	0.203 - 0.843 (0.442)	4.0	13
Watertube W/ Air Preheat	8	5.8	66.8 - 188 (134)	0.155 - 0.438 (0.312)	4.6	12
All Boiler Types	22	5.7	66.8 - 362 (155)	0.155 - 0.843 (0.360)	4.0	11

Equipment Type	No. Boilers Tested	Distillate Oil				
		Baseline			Low Excess Air	
		02 %	NO_x Emissions ng/J[a]	NO_x Emissions lb/10^6 Btu[a]	02 %	NO_x Reductions %
Firetube	2	5.4	96.5 - 107 (102)	0.224 - 0.248 (0.236)	3.2	18
Watertube W/O Air Preheat	3	5.5	44.7 - 59.5 (51.8)	0.103 - 0.138 (0.120)	3.2	6
Watertube W/ Air Preheat	2	5.4	69.0 - 102 (86.5)	0.160 - 0.237 (0.199)	4.5	12
All Boiler Types	7	5.8	44.7 - 107 (72.6)	0.104 - 0.248 (0.169)	3.7	11

[a] NO_x emissions are given as a range, with the average in parentheses.

T-1749

TABLE 2-6. COMBUSTION MODIFICATION NO_x CONTROLS FOR OIL-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	No. of Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)		Range of Application	Availability/ R&D Status	Comments
			Residual	Distillate Oil			
Low Excess Air (LEA)	Reduction of combustion air	22 residual oil boilers, 7 distillate oil boilers	0 to 28 11 average or 10 ng/J/ % O_2 reduction.	0 to 24 11 average or 10 ng/J-1/ % O_2 reduction.	Generally excess O_2 can be reduced to 2.5% representating a 3% drop from baseline.	Available.	Added benefits included increase in boiler efficiency. Limited by increase in CO, HC, and smoke emissions.
Staged Combustion Air	Fuel rich firing burners with secondary combustion air ports	3 residual boilers, 1 distillate oil boilers	20-50	17-44	70-90% burner stoichiometries can be used with proper installation of secondary air ports	Technique is applicable on packaged and field-erected units. However, not commercially available for all design types	Best implemented on new units. Retrofit is probably not feasible for most units especially packaged ones.
Burners Out of Service (BOOS)	One or more burners on air only. Remainder firing fuel rich.	8 boilers	10 to 30	N/A	Applicable only for boilers with minimum of 4 burners. Best suited for square burner pattern with top burner as BOOS. Only for retrofit application.	Available. Retrofit requires careful selection of BOOS pattern and control of air flow.	Retrofit often requires boiler derating unless fuel delivery system is modified.
Flue Gas Recirculation (FGR)	Recirculation of portion of flue gas to burners	On distillate oil boilers. Two residual boilers.	15 - 30	58 to 73	Up to 25-30% of flue gas recycled. Can be implemented on all design types.	Available. Requires extensive modifications to the burner and windbox.	Best suited for new units. Costly to retrofit. Possible flame instability at high FGR rates.
Flue Gas Recirculation plus staged combustion	Combined techniques of FGR and staged combustion	Only one package watertube	25 to 53	73 to 77	Max. FGR rates set at 25% for distillate oil and 20% for residual oil.	Combined techniques are still at experimental stage. Needs more R&D feasibile only for new units.	Retrofit may not be feasible. Best implemented on new units

Continued

T-1752

TABLE 2-6. CONCLUDED

Control Technique	Description of Technique	No. of Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)		Range of Application	Availability/ R&D Status	Comments
			Residual	Distillate Oil			
Load Reduction (LR)	Reduction of air and fuel flow to all burners in service	17 residual oil-fired boilers, 7 distillate oil-fired boilers	33% decrease to 25% increase in NO_x	31% decrease to 17% increase in NO_x	Applicable to all boiler types and sizes. Load can be reduced to 25% of maximum	Available now as a retrofit application. Better implementated with improved firebox design	Technique not effective when it necessitates an increase in excess O_2 levels, LR possible implemented in new designs as reduced combustion intensity (enlarged furnace plan area)
Low NO_x Burners (LNB)	New burner designs with controlled air/fuel mixing and increased heat dissipation.	Large number tested in Japan	20-50%	20-50%	New burners described generally applicable to all boilers. More specific information needed.	Commercially offered but not demonstrated	Specific emissions data from industrial boilers equipped with LNB are lacking
Ammonia Injection	Injection of NH_3 as a reducing agent in the flue gas.	5 (4 Japanese installations, 1 domestic)	40-70%	40-70%	Applicable for large package and field-erected watertube boilers. Not feasible for firetube boilers.	Commercially offered but not demonstrated	Some increased maintenance of air heater/economizer parts might be necessary when burning high sulfur oil. Technique is very costly.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater	2 residual oil-fired boilers	5-16%	--	Combustion air temp. can be reduced to ambient conditions (340K)	Available. Not implemented because of sigficant loss in thermal efficiency.	Application of this technique on new boilers necessitated installation of heat recovery systems in the flue gas

T-1752

availability of these techniques for oil-fired industrial boilers. The following subsections high-light the major points of interest for each of the controls considered.

2.3.1 Low Excess Air (LEA)

Low excess air, as for coal-fired boilers, is an effective means of achieving reductions in NO_x with increased boiler efficiency for oil-fired units. The technique is applicable to all oil-fired industrial boilers and is easy to implement both in a retrofit case and in new boilers.

Firetube and small watertube industrial boilers are generally equipped with constant speed forced draft fans which supply air to the windbox. Air control is achieved by adjusting the vanes at the inlet to the fan. A reduction in air flow to the burner(s) is achieved by closing these vanes. The reduced air-fuel ratio lowers the excess air level in the furnace. Large oil-fired multiburner watertube boilers are equipped with variable speed forced draft and induced fans which can be controlled to vary the amount of air flow to the boiler. However, these units will probably require the use of compartmental windboxes in addition to fan control for even distribution of air flow to each burner.

Table 2-5 summarizes the performance of the LEA technique on specific industrial boiler equipment types burning fuel oil. In general, the data show that LEA is equally effective for residual and distillate oil-fired boilers. NO_x was reduced by approximately 11 percent for both fuels. The data also show that for residual oil-fired boilers LEA is slightly more effective when applied on watertube than on firetube units. The reverse is true for distillate oil-fired boilers. However, the data base is not sufficiently large to verify the significance of these trends.

Reducing the excess oxygen in the flue gas by decreasing the air flow to the burner can lead to a rapid increase in CO, hydrocarbon and smoke emissions. However, the field test data for many boilers has shown that as long as the excess O_2 is maintained above 3.0 percent these emissions were not increased (Reference 2-18).

In addition to reducing NO_x emissions the technique of LEA is cost effective because it increases boiler efficiency. In fact, the thermal efficiency of all oil-fired units tested increased 0.7 percent on the average with LEA combustion (Reference 2-20).

Application of low excess air combustion requires not only means of adjusting air flow at various boiler loads, but also installation of flue gas O_2 and CO monitors. Attempts to adjust for LEA without controls may lead to a loss rather than a gain in efficiency. Alarms should also be installed to provide a safety system in case the air flow to the boiler is inadequate.

Low excess air combustion should be considered a standard operating practice for industrial boilers. In fact, because of the increased fuel efficiency the technique is often implemented strictly as a fuel economy device.

2.3.2 Staged Combustion

The concept of staged combustion consists of injecting secondary air downstream of a first stage combustion zone which is characterized by substoichiometric levels of combustion air. Stage combustion can be effected by use of secondary air ports/injectors or by burners out of service. Which of these techniques can be implemented on oil-fired boilers will depend on the type of furnace design.

The diversity of air injection systems designs applicable to oil-fired industrial boilers warrants a separate discussion for each of the major equipment design types previously identified.

2.3.2.1 Firetube Boilers

Figure 2-7 shows a schematic of an experimental retrofit application of the staged combustion technique, staged combustion air injection (SCA), on a firetube boiler burning residual oil.

The retrofit design consists of eight stainless steel pipes connected through a ring mainfold to a forced draft fan. The air injection pipes penetrate the furnace opposite from the burner and are equipped with "fish tail" orifice to assist in mixing the air with the combustion products. A separate fan provides air to the manifold independent of the burner air. This technique assures control of burner stoichiometry while supplying enough air downstream of the burner to complete combustion. The retractable injection nozzles permitted the analysis of the effect of injection air location on the performance of the staged combustion technique at various burner air-fuel ratios.

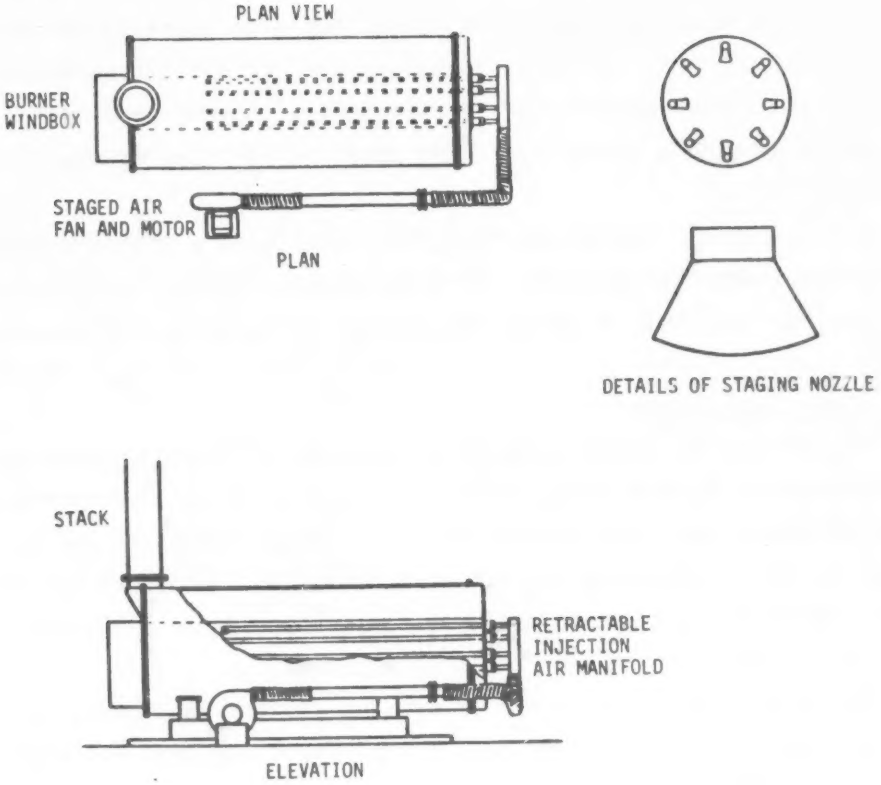


Figure 2-7. Schematic of staged combustion air injection for an oil- and gas-fired firetube boiler (Reference 2-54).

The retrofit design shown in Figure 2-7 represents a possible way of implementing SCA on firetube boilers. Alternate solutions would be to perforate the front or the side of the boiler to accomodate the injection nozzles.

Staged combustion test results are available only for residual oil. NO_x was reduced from 96.2 to 49 ng/J (0.224 to 0.114 $lb/10^6$ Btu) with a burner stoichiometry of 76 percent and the injection air ports located 2.5 firebox diameters downstream of the burner oil tip. The overall excess oxygen level was 4 percent. The boiler load was, however, reduced to 50 percent of capacity because combustion instabilities were encountered at high loads as the air flow through the windbox was reduced (References 2-52 and 2-53). It should be noted that these instabilities could be partly attributed to removal of burner baffles under the staged combustion tests. The significant NO_x reduction achieved indicates that the staged combustion technique can be very effective in reducing NO_x emissions from firetube boilers burning residual oil. This technique is expected to be less effective for distillate oil combustion because of the lower fuel NO_x formation with this fuel.

Staged combustion air (SCA) injection should be considered still in the development stage. More testing is required to resolve the combustion instability at the high boiler loads and to establish the reliability of the system for long-term operation. In addition, the design of the SCA system as shown in Figure 2-7 might not be feasible altogether because of operational complexity and incremental cost.

2.3.2.2 Packaged Watertube

Two retrofit designs of the staged combustion technique have been investigated for single burner packaged watertube boilers. Figures 2-8 and 2-9 show the schematic of two secondary air injection systems.

In the first retrofit application (Figure 2-8), the staged combustion air was injected from the side of the furnace. The application was possible because the configuration of the waterwalls was not of the tangent type. That is, refractory brick spacing existed between furnace waterwall tubes. Consequently air could be injected without having to modify or remove any of the furnace tubes. This type of waterwall tube design is typical of oil boiler furnaces. Modern manufacturing methods utilize tangent tube construction for better radiant heat transfer.

Figure 2-9 shows an alternate method of injecting staged air combustion in a modern design "D" type package watertube boiler. Holes were drilled in the windbox and four retractable air injection lances were installed directly in the furnace. The tangent tube design of this furnace did not permit side air injection. The movable lances permitted injection of air at varying distances downstream of the burner. This injection system was designed for the purpose of conducting experimental tests and should not be considered as an established method of injecting secondary air in this boiler type. However, it may be possible to design the tube arrangement in new boilers such that air injection ports could be installed on the side of the furnace.

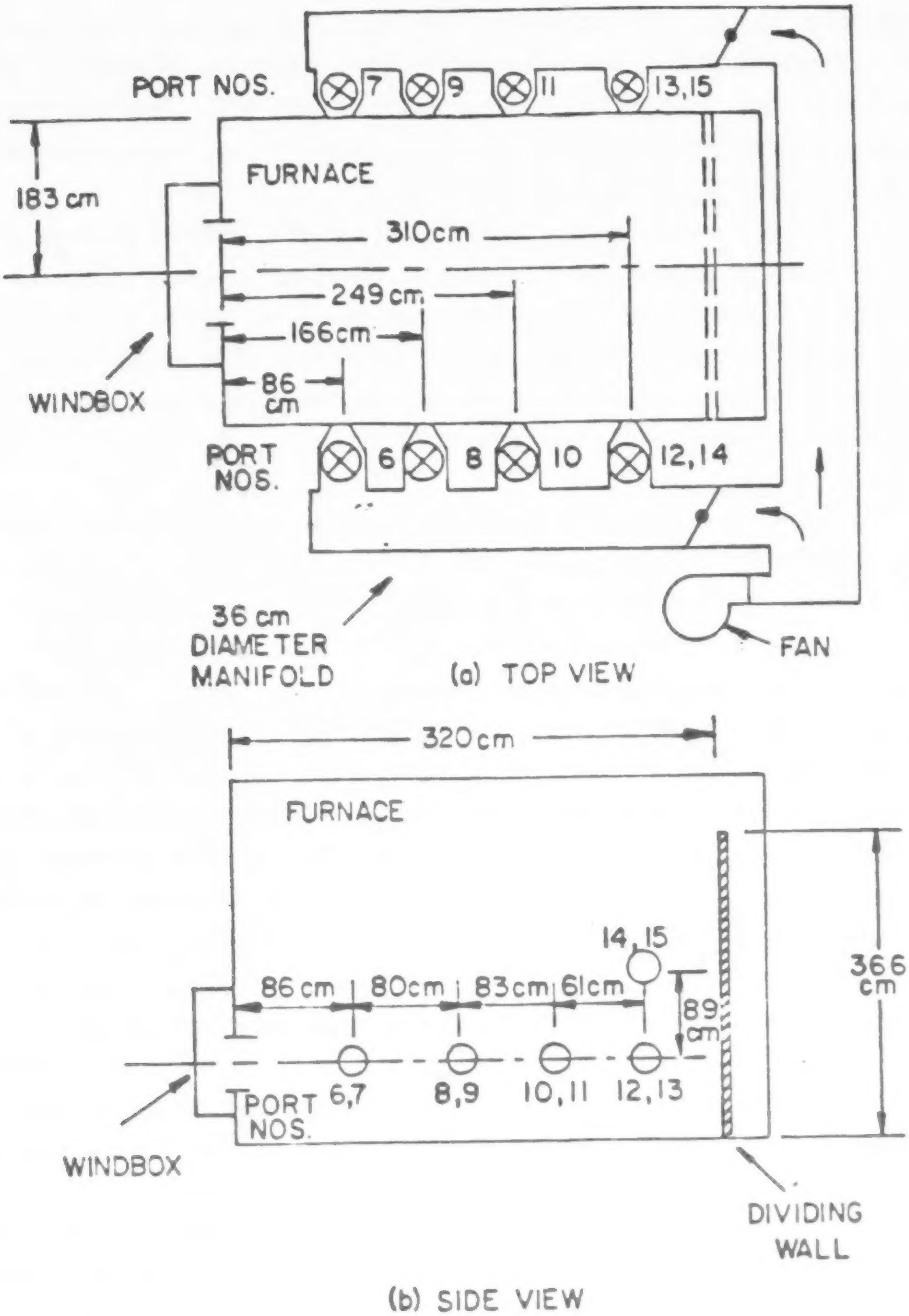
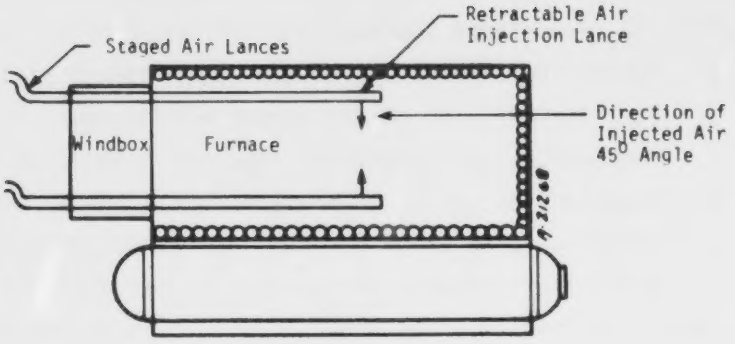
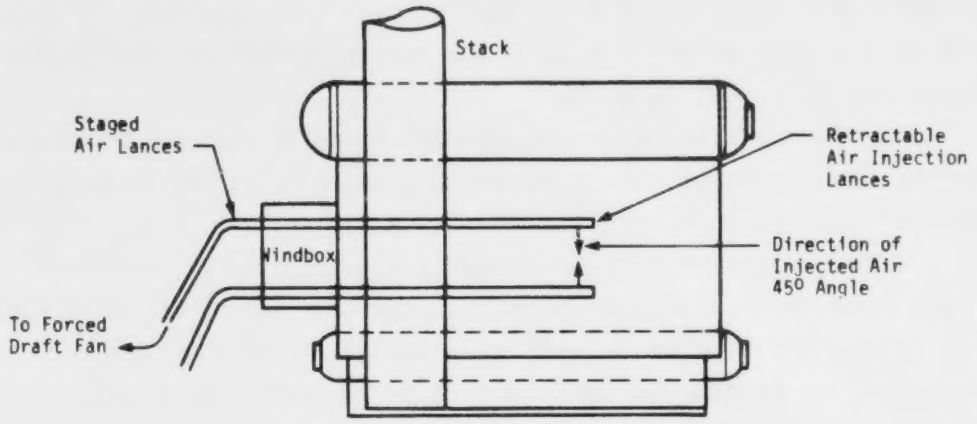


Figure 2-8. Schematic of staged air system installed for single burner packaged watertube oil-fired boilers (Reference 2-55).


Retractable Air Injection Lance
Staged Air Lances
Direction of Injected Air 45° Angle
Windbox
Furnace
A-31268

(a) Top View


Stack
Staged Air Lances
Retractable Air Injection Lances
Direction of Injected Air 45° Angle
Windbox
To Forced Draft Fan

(b) Side View

Figure 2-9. Schematic of stage air system installed on "D" type packaged watertube boiler (Reference 2-55).

Results on the performance of staged combustion on single burner watertube boilers suggest that two conditions are required to achieve substantial NO_x reductions (References 2-20 and 2-55).

- Burner stoichiometries must be set between 90 and 100 percent. That is, air flow to the burner windbox must be below theoretical air needed for complete combustion.
- Secondary air must be injected sufficiently downstream from the burner exit to allow for cooling of combustion gases. This downstream distance varies with burner type and size.

Carefully installed and operated staged injection air will result in significant NO_x reductions (40-45 percent) from residual oil-fired package boilers. However, as in the case with firetube boilers it is estimated that more field data on the long term effects of SCA in these units is necessary before this technique can be considered demonstrated.

2.3.2.3 Field Erected Watertube

For field erected watertube boilers, normally equipped with more than one burner, staged combustion can be obtained with the techniques of overfire air (OFA) or burners out of service (BOOS).

The technique of OFA has already been described for coal-fired boilers (Section 2.2.1.2). Overfire air injection above the top burner level is applicable to new as well as existing oil-fired boilers. However, as in the case for coal-fired units the technique is more attractive in original designs than in retrofit applications for cost considerations. Information on NO_x reduction from oil-fired industrial boilers using OFA is very limited. However, application of the technique on utility boilers burning oil has resulted in 24 percent NO_x reduction (Reference 2-24). Overfire air is a viable NO_x reduction technique for new multiburner industrial units burning oil. Furthermore, it is considered demonstrated and commercially available.

Burners out of service is the simplest method of achieving staged combustion with these units. However, this technique is usually limited to retrofit applications. The method of implementing BOOS has already been described in Section 2.2.1.3 for coal-fired units. The application to oil-fired units is essentially the same except that oil-fired units have better control over the number or location of the burner(s) to be used as air injection ports. This is possible for oil and also gas units because the fuel flow can be terminated at each individual burner and not at a set of burners as in the pulverized coal-fired units. Furthermore, fuel feed rates to the active burners can be adjusted over a broader range for oil- and gas-fired boilers. Numerous field test data on burners out of service have been gathered on industrial boilers. NO_x emissions were reduced 25-40 percent during these tests (References 2-4 and 2-20).

On existing units, operation with BOOS requires that the unit be derated unless modification to the fuel delivery system is made. In addition, adjustments to the air flow controls, such as burner registers, might also be required to achieve the required burner stoichiometry without increasing smoke and combustible emissions. Furthermore, there is no optimum BOOS pattern applicable to all existing boilers (Reference 2-20).

2.3.3 Flue Gas Recirculation (FGR)

Recycling a portion of the flue gas back to the primary combustion zone reduces NO formation by lowering the bulk furnace gas temperature and reducing oxygen concentration. Figures 2-10 through 2-12 show schematics of typical FGR retrofit applications on a firetube and two packaged watertube boilers, respectively. The systems are nearly identical consisting of an FGR fan assembly and associated ducting connecting the stack to the windbox.

One investigator reported that the technique is more effective for watertube boilers than for firetube boilers when burning the same fuel because of the generally higher combustion intensity of the watertubes (Reference 2-52). However, NO_x reductions for both firetube and watertube reached a maximum of 20 percent when burning a residual oil. Another investigator reported that FGR is more effective for steam atomized oil combustion than for air atomized oil combustion (References 2-20 and 2-55). In fact, in a watertube boiler burning steam atomized residual oil, maximum NO_x reduction was 20 percent. When burning the same oil with air atomization only 16 percent NO_x reduction was achieved.

For oil-fired boilers FGR is more effective when burning light distillate oil because thermal NO_x predominates. In fact, NO_x reductions of up to 73 percent were obtained with FGR when burning a No. 2 distillate oil (Reference 2-55).

In a retrofit application, flue gas recirculation rates approaching or above 30 percent can cause severe flame instability, flame pulsation,

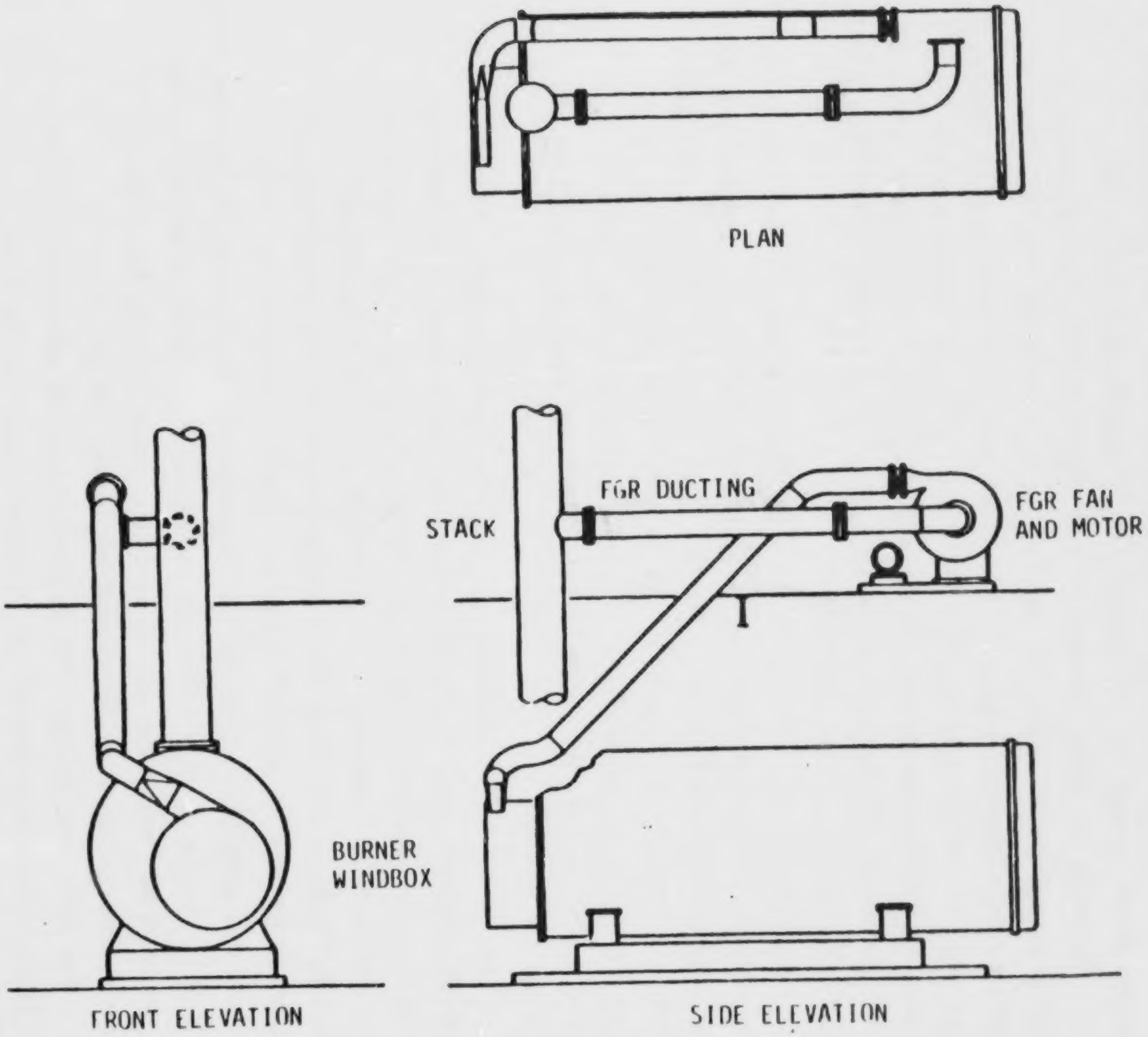
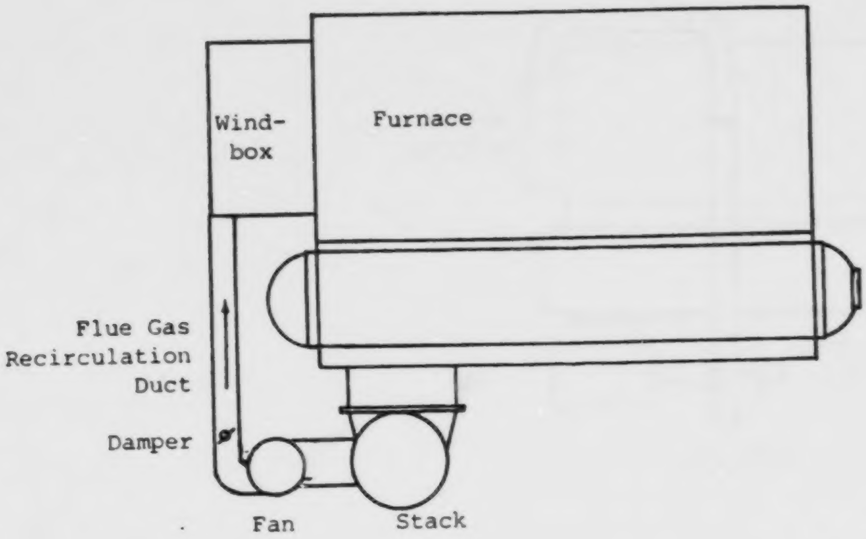
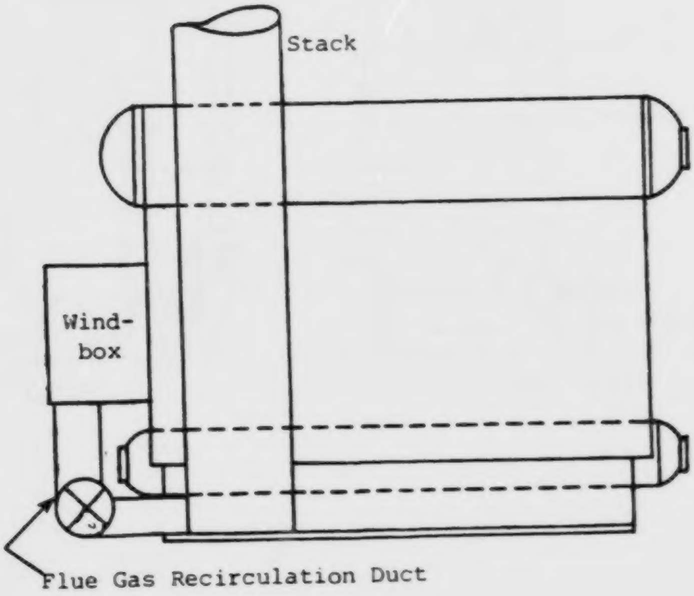


Figure 2-10. Layout of flue gas recirculation system for a firetube boiler (Reference 2-54).



(a) Top View



(b) Side View

Figure 2-11. Layout of flue gas recirculation system for a packaged watertube boiler (Reference 2-55).

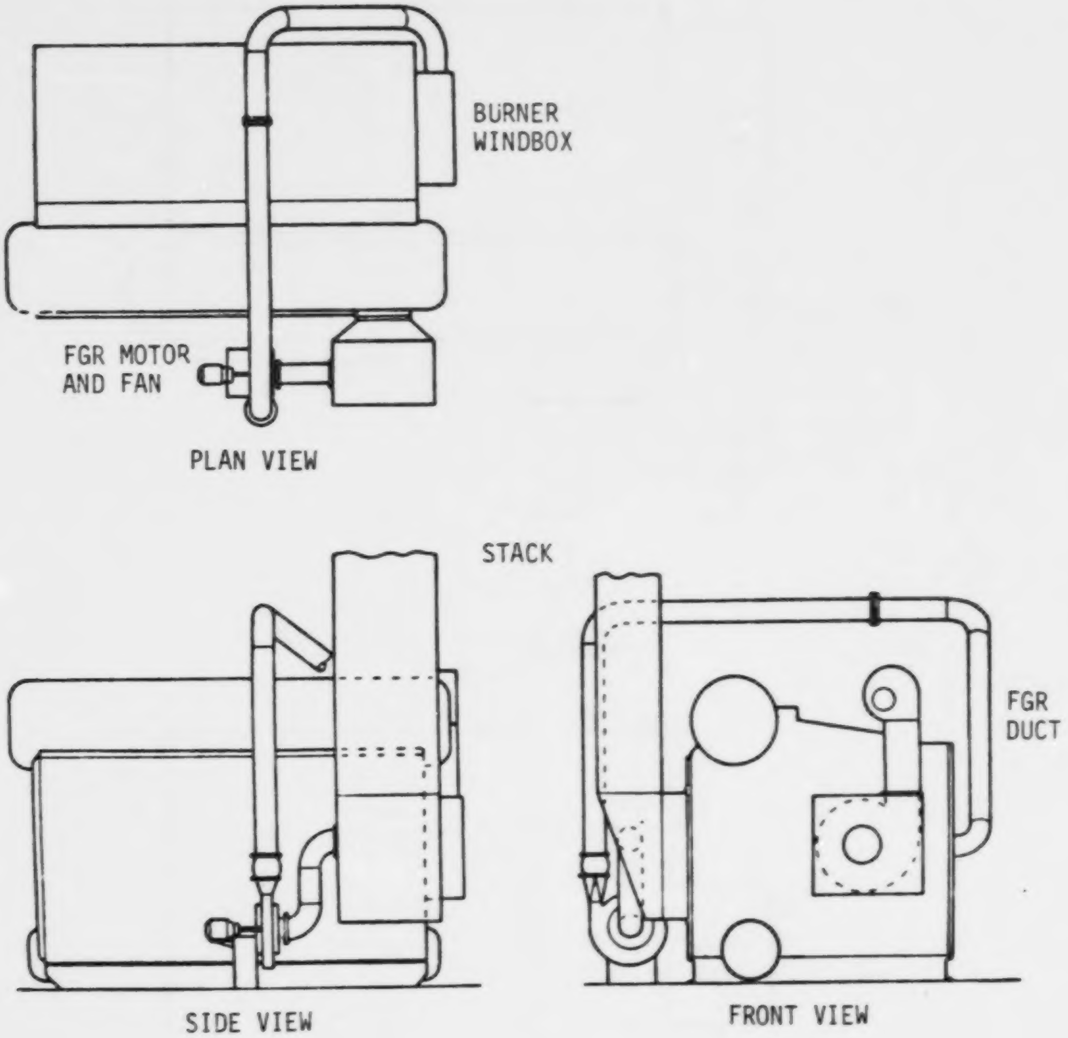


Figure 2-12. Alternate layout of flue gas recirculation system for a packaged watertube boiler (Reference 2-54).

equipment vibration and blowouts. These problems were found to be significantly alleviated by extensive burner and windbox modifications (References 2-20 and 2-52).

In general, FGR is definitely an applicable control technique for oil-fired industrial boilers. It is most effective on boilers burning distillate oil. When burning residual oil, steam atomization is preferred. The technique is commercially available for new boilers for which burners have been designed to accomodate the additional flue gas flow. In fact, one manufacturer has recently installed two 14.7 MW (50×10^6 Btu/hr) units equipped with FGR systems in Southern California (References 2-56 and 2-57). No information on the performance on these units has been reported. However, the NO_x emissions of these units are designed to meet the stringent regulations of the South Coast Air Basin of 225 ppm at 3 percent O_2 for oil combustion (approximately 126 ng NO_2/J).

2.3.4 Combined Flue Gas Recirculation and Staged Combustion

The packaged watertube boiler shown in Figure 2-9 was also tested with combined SCA and FGR. Tests were run to determine whether the effectiveness of the two techniques are additive (References 2-20 and 2-55). Combining SCA with FGR gave no increased reduction over that with FGR or SCA alone when burning distillate oil. However, the combined techniques had a pronounced effect when burning residual oil. Thus staged combustion alone reduced NO_x emissions of residual oil 42 percent, FGR alone reduced NO_x emissions 11 percent while FGR with SCA reduced the NO_x emission 55 percent.

Fitting a boiler with both SCA and FGR may not prove to be cost effective. The combined technique is not considered commercially available because staged combustion is still experimental for firetube and packaged watertube boilers.

2.3.5 Reduced Air Preheat (RAP)

Reducing the amount of combustion air preheat lowers the primary combustion zone peak temperature, generally lowering thermal NO_x production as a result. The technique can be implemented only on boilers equipped with air preheaters. These boilers are of the watertube type and generally have designed heat input capacities of greater then 15 MW (50×10^6 Btu/hr) (Reference 2-20). No retrofit work is required in some instances.

As evidenced by the data contained in Table 2-5, baseline NO_x emission data from distillate oil-fired watertube boilers equipped with air preheaters had greater NO_x emissions than those units not equipped with air preheaters. Unit capacity was not a factor. No similar reduction occured for those units burning residual oil, perhaps because of the greater variation in fuel nitrogen content of the various oils being burned.

The data reported in Table 2-6 reflects results of RAP tests on two residual oil-fired boilers. For one boiler where the initial baseline NO_x emissions was below 200 ppm at 3 percent O_2 (112 ng/J) the technique was ineffective. For the other boiler with initial baseline emissions over 330 ppm at 3 percent O_2 (185 ng/J), RAP reduced NO_x emissions at a rate of 33 ppm (19 ng/J) per 50K (90^oF) reduction in combustion air temperature (Reference 2-20).

Although available, the technique is rarely applied because very few industrial size oil-fired boilers are equipped with air preheaters. Furthermore, when RAP can be implemented, the fuel penalty involved due to loss in efficiency makes the technique very unattractive. Reducing the air preheat temperatures as a means of reducing nitrogen oxide emissions from oil-firing will result in a decrease in boiler efficiency by about 2.5 percent per 50K (90^oF) increase in stack temperature (Reference 2-20 and 2-58). Because of this significant loss in boiler efficiency, the heat loss would have to be recovered if RAP is to be used as a NO_x control technique. Enlarging the surface area of existing economizers or installation of an economizer in place of an air preheater can be used to recover the heat loss due to the RAP technique for NO_x control. For new boilers, installation of an economizer is technically feasible and also offers economic advantages over the air preheater (Reference 2-59).

2.3.6 Load Reduction

Reducing boiler load is accomplished by reducing the heat input into the furnace. Both heat release rate (also known as combustion intensity) and peak flame temperature are lowered, reducing the themal NO_x formation. However, the reduced mass flow through the burners at the reduced load condition can cause improper fuel-air mixing, thus creating CO and soot emission with additional operational problems. This situation is alleviated by increasing the air flow to excess air levels higher than normally maintained at the higher boiler loads. This increase in air flow causes more oxygen availability, thus favoring increase in fuel NO_x formation. The net effect of reduced thermal NO and increased fuel NO is often no change in NO_x concentration in the flue gas.

This was essentially the result of the load reduction tests conducted in an EPA program on 24 oil-fired industrial boilers (References 2-4, 2-20 and 2-53). The data often show a split with some boilers increasing NO_x emissions at reduced loads and other boilers decreasing them. For firetube boilers burning distillate oil, the NO_x emissions ranged from a 10 percent decrease to a 7 percent increase for each 10 percent load reduction. Five distillate oil-fired boilers without air preheat shown an average increase in NO_x emission of 3.8 percent while the remaining two with air preheat showed an average decrease in NO_x emissions of 26 percent. NO_x emissions from firetube and watertube units burning residual oil showed average decreases in NO_x emission factors regardless of whether the air was preheated or not.

Reducing boiler load will usually reduce the thermal efficiency of the boiler because of the increase in excess air needed to maintain good fuel air mixing. A more desirable way to achieve a reduction in combustion intensity would be to increase the size of the firebox. The enlarged firebox would provide reduced heat release rates without necessitating an increase in excess air levels. Naturally, the increased firebox design will only apply to new boilers. This technique is being implemented on utility size boilers (Reference 2-24).

2.3.7 Low NO_x Burners (LNB)

Low NO_x burners firing fuel oil can generally be classified by the method of fuel injection and the method of combustion air delivery. A recent EPA study (Reference 2-60) further classifies the burners as:

- Good-mixing*
- Divided flame
- Self-recirculating

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*Controlled-mixing is probably a less confusing term, but "good-mixing" was the term used by the EPA report and will be retained here.

- Staged-combustion
  - -- Two stage combustion
  - -- Off stoichiometric combustion

The good-mixing and dividea flame type burners primarily reduce thermal NO_x, either by rapid quenching of the flame, or by an increase in the surface area of the flame for increased heat dissipation. The self-recirculation and various staged-combustion type burners reduce both thermal and fuel NO_x. This is accomplished through the recycling of combustion gas, which is lean in oxygen, or substoichiometric air injected in the primary combustion zone with stoichiometric and excess air added at the point of fuel discharge into the furnace.

Seven types of low NO_x burners for industrial boilers are presently under development or in commerical use in Japan. A summary of the limited information regarding each of these burners is presented in Table 2-7. Available information on the operations, performance, applicability and availability of each of these burners is discussed in the following sections. Unfortunately, actual emissions data for low NO_x burners for industrial boilers are generally not available. The percentage NO_x reductions presented here are only the expected performance as cited in the references, usually with no baseline emission levels given.

Nippon/TRW Burner

The Nippon/TRW burner is designed to allow for an initial fuel-air mixing zone, established through precise control of the radial injection and atomization of the fuel into the combustion air. A second mixing zone allows for heterogenerous mixing of fuel droplets, followed by the primary flame front and post combustion zone (Reference 2-61).

The intermixing of fuel and air produces a radial conical flame pattern as shown in Figure 2-13. The combination of the recirculation of combustion products and good-mixing of fuel and air leads to reduced NO_x emissions by rapid quenching of the flame with cooler combustion gases. Figure 2-13 also shows the flame as being a thin annular configuration for increased heat dissipation and lower flame temperatures. Both phenomena reduce thermal NO_x production.

Figure 2-14 presents the results of the demonstration/commercialzation tests performed by Nippon/TRW. The sensitivity of NO_x emission

TABLE 2-7. LOW NO_x BURNERS FOR OIL AND GAS FIRING

Manufacturer Developer	Burner Type	Effectiveness of (Percent NO_x Reduction)	Applicability	Availability	Comments
Nippon/TRW	Good mixing[a]	17-23% w/heavy oil, fuel nitrogen content of 0.3%	Oil & gas	Commercialized early 1975 in Japan	Lower steam atomization but higher burner throat ΔP, High excess O_2
TRW/Civiltech	Good mixing[a]	17-23% w/heavy oil, fuel nitrogen content of 0.3%	Oil & gas	Late 1979	First generation burner tested in Japan. Second generation being developed for U.S.
Ishikawajima-Narima	Divided flame	30-50% reduction depending on application	Oil & gas	Commerically available in Japan (1973)	Requires burner tip modification only
Tokoyo Gas	Staged Combustion	50% reduction	Gas	Continuing development	Flame stability problems
Kawasaki	Staged Combustion	20-50% depending on fuel rate	Oil & gas	N/A	N/A
Coen	Staged Combustion	N/A	Oil & gas	Available on a very limited basis	Staged combustion design. All proprietary data
Energy and Environmental Research/EPA	Staged Combustion	Up to 50%	Oil	Still at R&D stage	Currently being tested in a field operating firetube

[a] Controlled mixing is probably a better term, but "good mixing" was the term used by the EPA study (Reference 2-60) and will be retained here.

T-1753

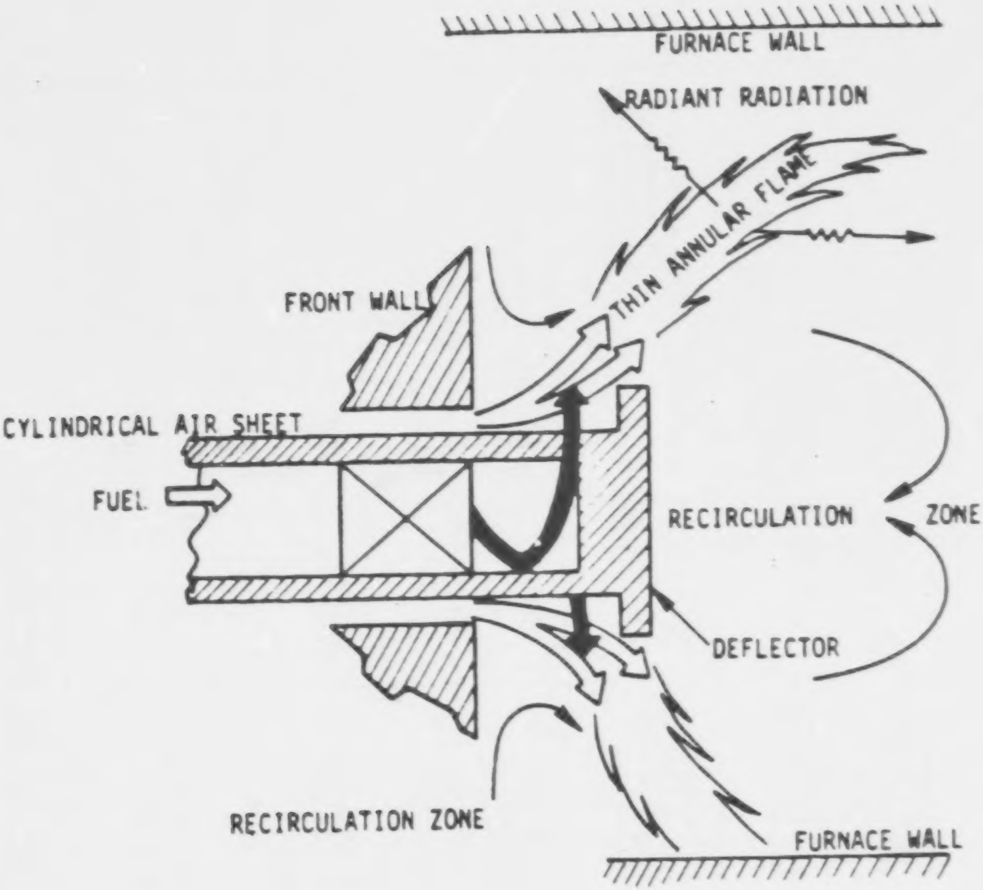


Figure 2-13. The Nippon/TRW burner (Reference 2-62).

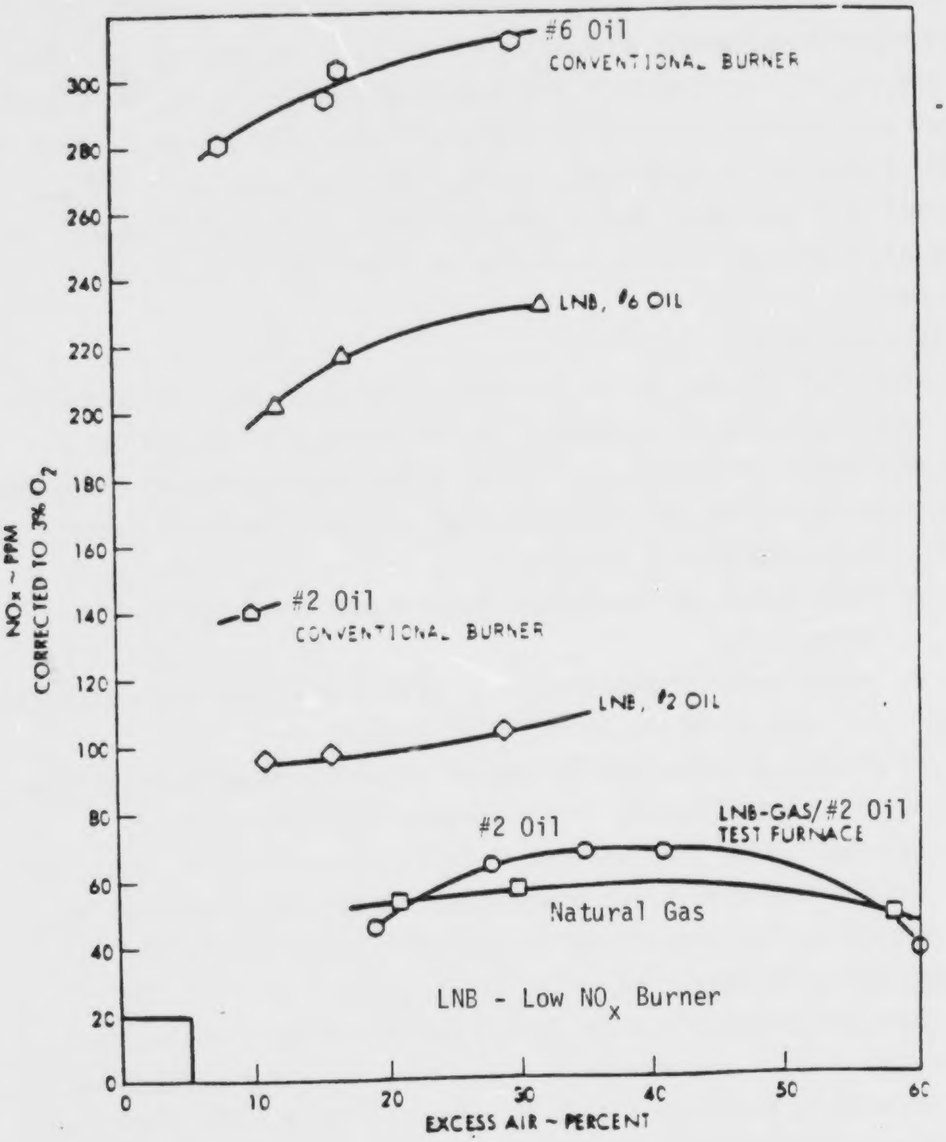


Figure 2-14. Performance results of the Nippon/TRW low NO$_x$ burner (LNB) (Reference 2-61).

concentrations as affected by fuel nitrogen is clearly seen. Figure 2-14 also demonstrates the low NO_x burner capabilities compared to a conventional burner. These tests were conducted after the burner was installed in an existing packaged boiler without modification to the safety control equipment, combustion air or fuel-handling system. The test results show a 35 percent decrease in NO_x emissions for No. 2 fuel oil and a 30 percent decrease for heavy oil (analysis unknown). When the low NO_x burner was in operation, all NO_x emissions were below 220 ppm corrected at 3 percent excess oxygen (123 ng/J, 0.287 lb/10^6 Btu). The burner has been commercially available in Japan since early 1975 (Reference 2-62).

TRW/Civiltech Burner

The TRW/Civiltech burner represents the second generation burner being developed based on experience obtained with the Nippon/TRW LNB (Reference 2-63). Problems experienced during testing in Japan have led to a program to refine the original burner design. The second generation burner is being designed to achieve:

- Reasonably low excess air requirements during partial load operations
- Wider range of applicability, with burner heat input capacities of 3 to 73 MW (10 to 250 x 10^6 Btu/hr)

As of this writing, the TRW burner is being commercially offered, though as yet undemonstrated. A preliminary timetable calls for commercial application near the end of 1979 (References 2-61, 2-63, and 2-77). An EPA sponsored field demonstrated is currently underway and actual operating data should soon be available (Reference 2-78).

Ishikawajima-Harima Heavy Industries (IHI) Burner

Ishikawajima-Harima Heavy Industries developed several burner configurations which are effective in reducing NO_x. The basic principle of the burners is a divided flame, as shown in Figure 2-15. The flame produced has a radial conical pattern which increases the radiation surface area and the rate of heat dissipation. The reduced flame temperature results in reductions in NO_x emissions.

The burner variations shown in Figure 2-15 were tested on a furnace simulator. The results are shown in Figure 2-16. NO_x concentrations are shown to be reduced by 30 to 50 percent of the emissions from

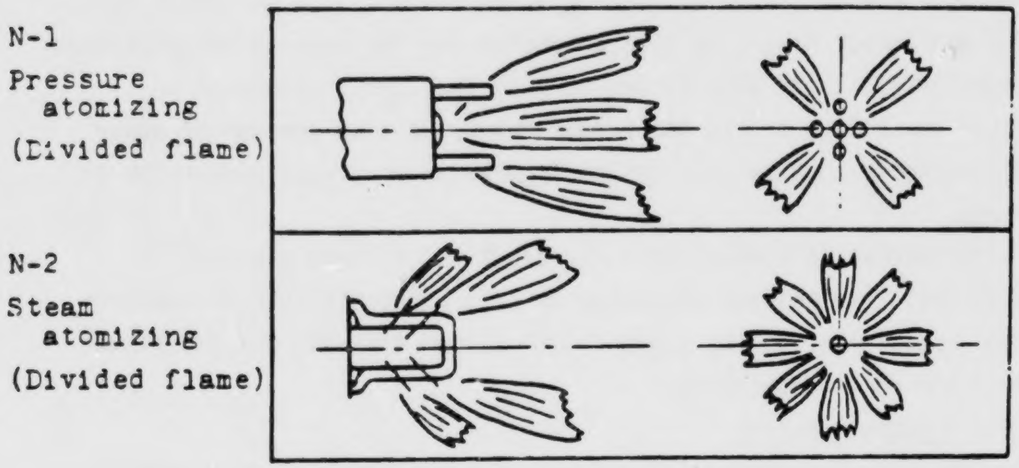
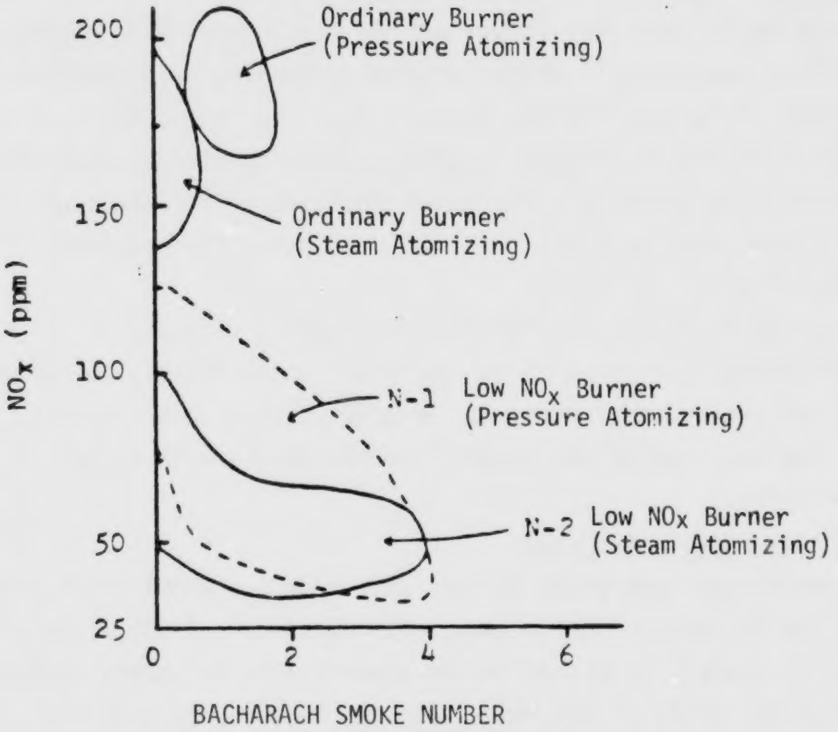


Figure 2-15. Ishikawajima-Harima divided flame burner (Reference 2-64).



NOTE: Enclosed regions represent data bands.

Figure 2-16. Effect of flame division on NO_x and smoke concentrations (Ishikawajima-Harima burner) (Reference 2-64).

conventional burners. Field tests on large boilers, 130 MW (400 x 10^6 Btu/hr) and larger have also been conducted and the results are presented in Figure 2-17. It is significant to note that combinations of NO_x reduction capability of the IHI burner are reduced as the use of other control methods, such as flue gas recirculation or staged combustion is increased.

The burner is commercially available for oil and gas fuel applications. The primary advantage to this burner is that it requires only the replacement of the conventional burner tip with the IHI flame divider, a minor modification.

Tokoyo Gas Company Burner

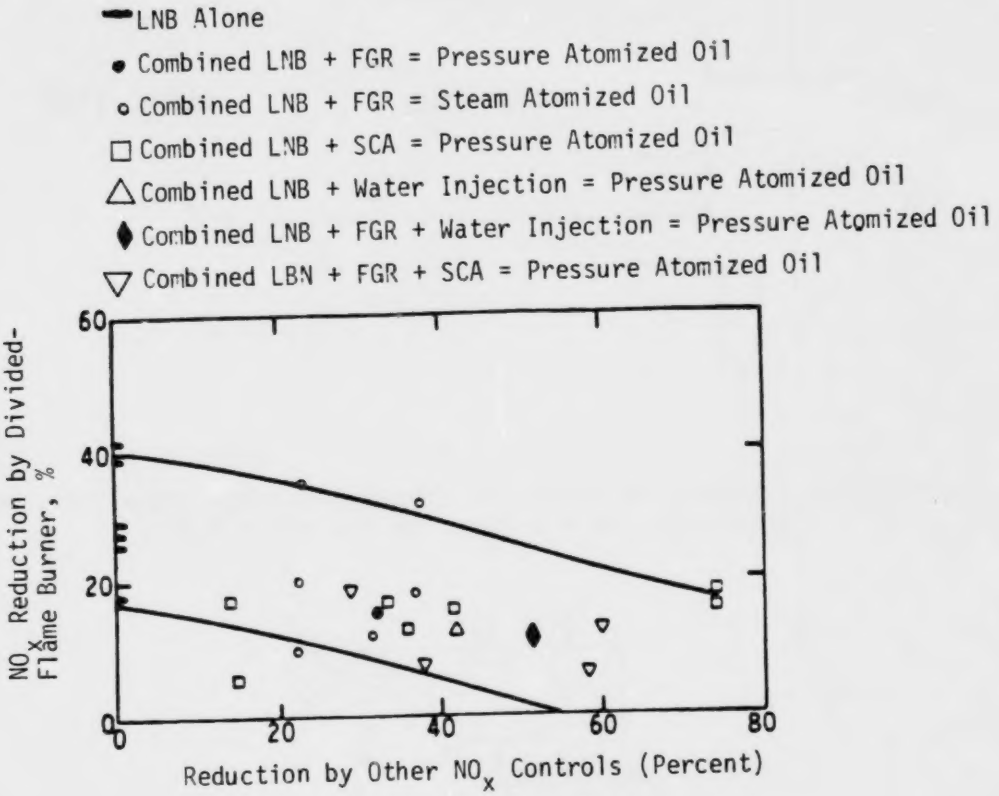
Tokoyo Gas company developed one of the first two-stage combustion type burners (Reference 2-65). The principle of the burner is shown in Figure 2-18. The primary air ports admit a predetermined air volume followed by stoichiometric addition as shown.

Experimental test results showed the presence of HCN and NH_3 intermediates, the radicals which Fenimore determined were precursors to the formation of "prompt NO" (Reference 2-66). To reduce the concentration of these radicals, a catalyst was inserted between the first and second combustion zones. The burner operates at the limit of fuel-rich combustion, resulting in some flame stability problems (Reference 2-65).

Tests conducted on a firetube boiler with a capacity of 5.5 MW (18.6 x 10^6 Btu/hr) resulted in NO_x emissions approximately 50 percent of those from conventional burners. Because of the flame stability problems, however, the burner is still in the development stages (Reference 2-65).

Kawasaki Heavy Industries Burner

A two-staged combustion burner, utilizing a precombustion zone, has been designed by Kawasaki Heavy Industries (Reference 2-60). The precombustion chamber is placed in the windbox with secondary combustion air added at the point of discharge into the furnace, as shown in Figure 2-19. The injection of the fuel oil results in an eddy effect, as in self-recirculating burners, resulting in fuel rich combustion. The fuel is vaporized and partially combusted. Secondary air is added, at the desired overall stoichiometry, at the burner tip. Reportedly, this



LNB = Low NO_x Burner
FGR = Flue Gas Recirculation
SCA = Staged Combustion Air

Figure 2-17. Effect of combined combustion modifications NO_x controls on the performance of the Ishikawajima-Harima low NO_x burner) (Reference 2-64).

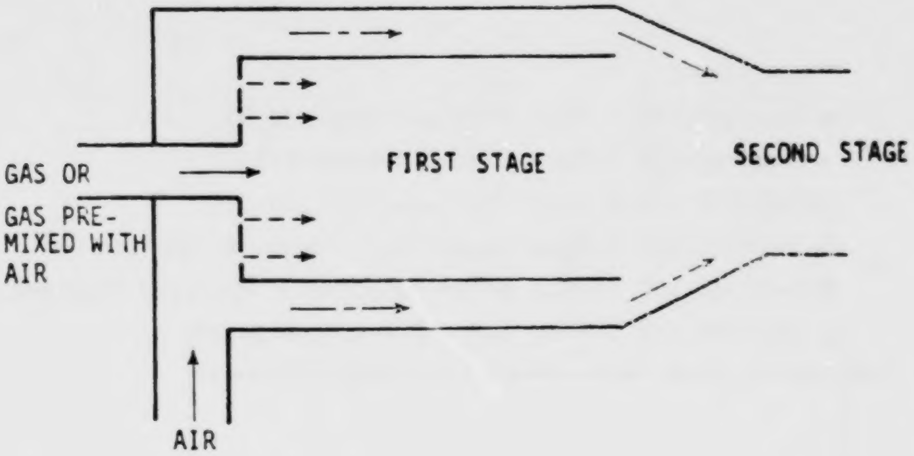


Figure 2-18. Schematic of Tokoyo Gas Company two-stage combustion type burner for low NO_x formation (Reference 2-60).

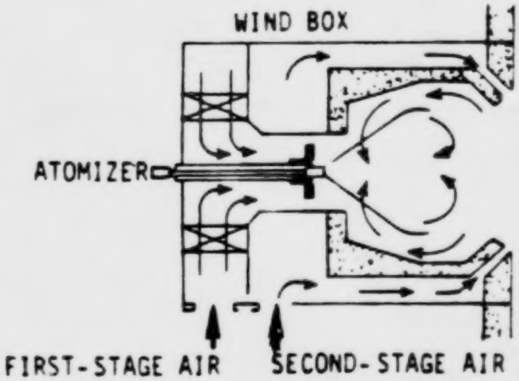


Figure 2-19. Kawasaki two-stage combustion-type burner for oil (Reference 2-60).

configuration reduces both thermal and fuel NO_x. The degree of reduction is shown in Figure 2-20.

Coen Burner

All test and descriptive information regarding the Coen low NO_x burner is considered proprietary (Reference 2-67). The information given was limited to burner concept (staged combustion) and applicable fuels (gas and oil). It was also stated that the burner was commercially available on an extremely limited basis. The flame is elongated, making the application to existing boilers difficult without substantial derating. All burners sold will be tested as part of a burner development program. Widespread commerical availability is not expected in the near future (Reference 2-67).

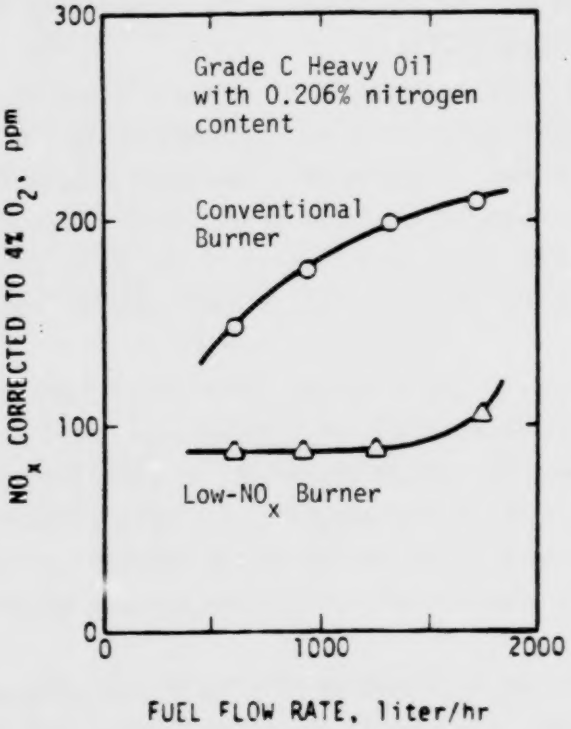


Figure 2-20. Effect of Kawasaki low NO_x burner on NO_x emissions (Reference 2-60).

Energy and Environmental Research Co. (EER) EPA Burner

EER recently tested an oil-fired low NO_x burner in a firetube boiler. Reductions in NO_x emission levels of greater than 50 percent have been achieved without the need to modify the boiler in any way (Reference 2-68). Apparently the burner has not been fully demonstrated because additional testing is underway to investigate the effect of oil atomization. Preliminary results with this burner have been very encouraging; however there is no indication on future availability.

2.3.8 Ammonia Injection

The non-catalytic reduction of NO in the flue gas with NH_3 is commercially available in Japan. Four industrial steam generators ranging in size from 41 to 252 MW (140 to 860 x 10^6 Btu/hr) have been successfully retrofitted in Japan. Reported NO_x reductions ranging from approximately 40 to 65 percent depending on the temperature of the injection location (Figure 2-21).

Since the commercial application of ammonia injection process in Japan, one domestic application on an oil recovery boiler in Southern California has taken place. Reported NO_x reductions ranged from 50 to 70 percent with the unit burning a heavy crude oil (Reference 2-69). The technique is particularly attractive because it can be in combination with any other combustion modification. Thus, significant NO_x reductions can be achieved.

For firetube boilers the injection system would need to be placed in the firebox as it is shown in Figure 2-22 because optimum temperatures occur at this location. The system represents an experimental retrofit application for a pilot scale test program. For watertube boilers the injection system will have to be located at the entrance of the convective section where flue gas temperatures are optimum for the NO reduction reaction to occur.

Due to the expected high cost of this technique compared with other combustion modifications, the ammonia injection process will probably not be feasible on small size boilers such as firetubes and package watertubes. In addition, since these industrial units are generally not base loaded, that is they do not operate at a steady continuous load, the variable heat input will cause significant flue gas temperature fluctuations which will reduce the performance of the control technique.

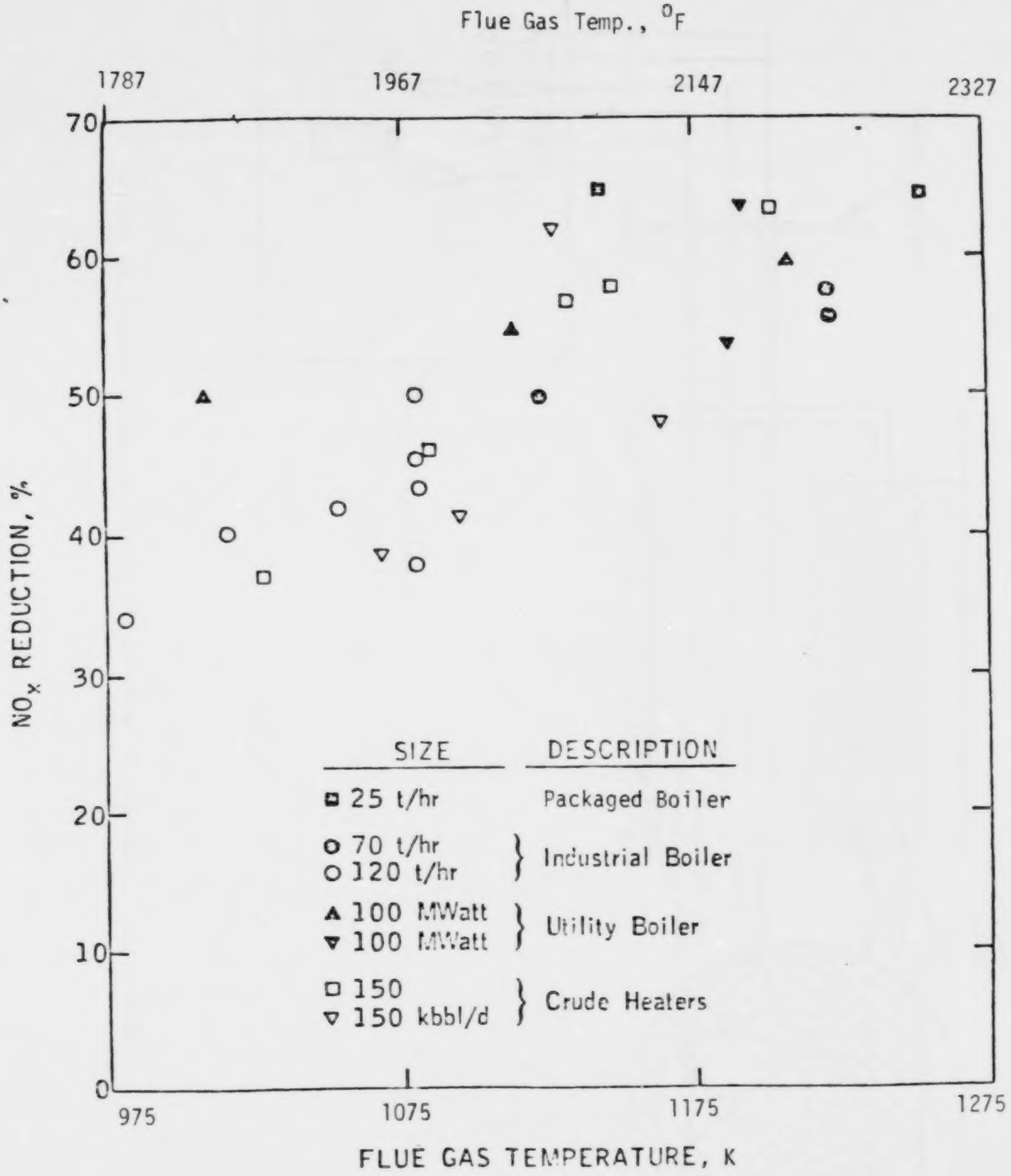


Figure 2-21. Ammonia injection system performance on commercial units as functions of temperature (Reference 2-70).

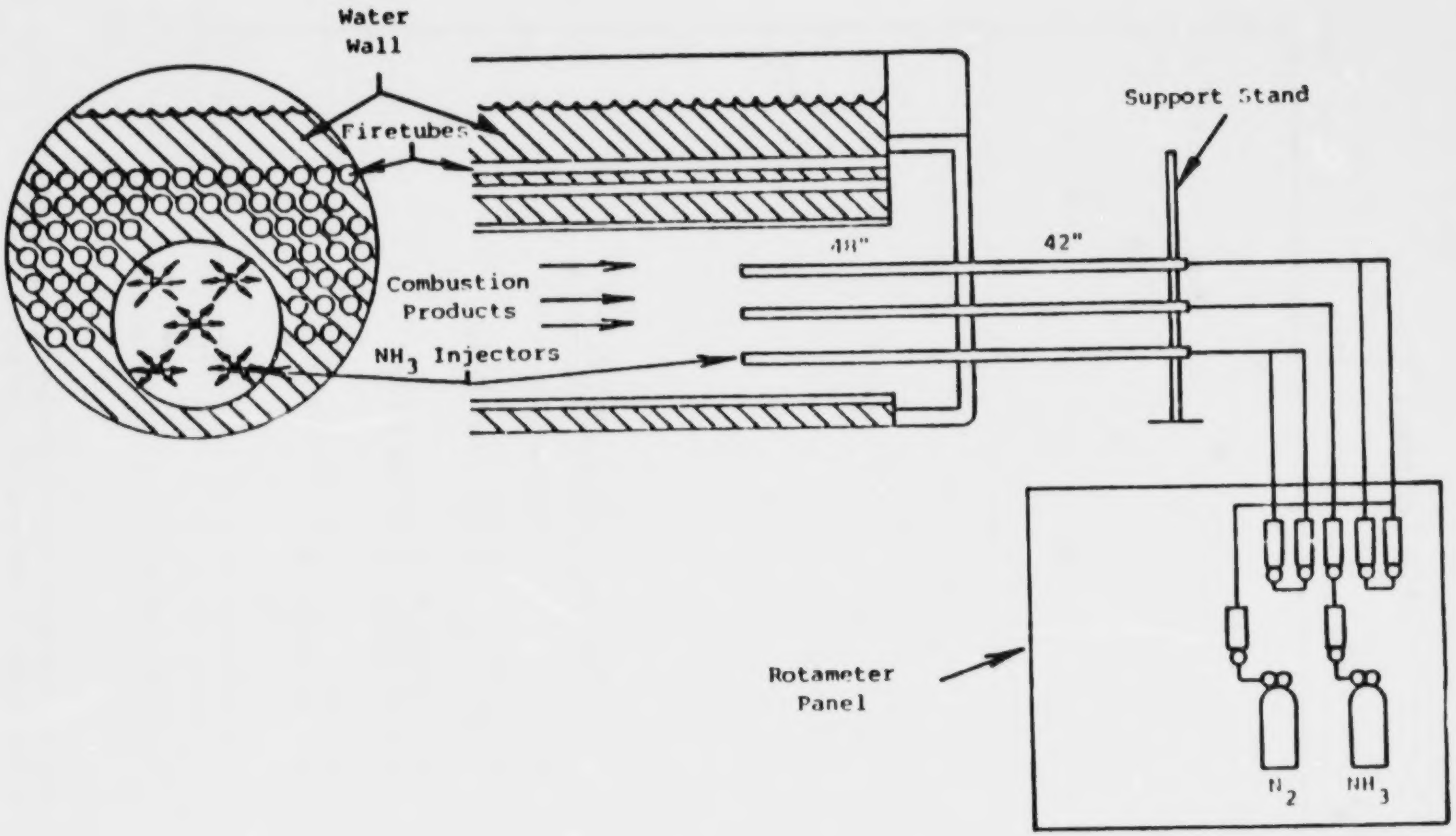


Figure 2-22. Schematic of ammonia injection system on a firetube boiler (Reference 2-18).

From an operational standpoint, the ammonia injection process is best suited for units burning low sulfur oil. The absence of SO_3 in the flue gas will eliminate the concern for corrosive deposits caused by the formation of ammonium sulfates.

2.4 GAS-FIRED BOILERS

Gas-fired industrial boilers are of the same basic design as oil-fired boilers. In fact, approximately one-fourth of all industrial boilers are capable of burning gas and oil individually or in combination (Reference 2-44). Gas-fired boiler designs are categorized as firetubes, and packaged or field-erected watertubes. Of the total population of installed units, gas-fired firetubes comprise 11.3 percent, packaged watertubes 8.6 percent and field-erected watertubes 13.6 percent (Reference 2-2).

Table 2-8 lists baseline NO_x emission from gas-fired industrial boilers tested by EPA (References 2-4, 2-20 and 2-53). The data show a definite increase in NO_x emissions for boilers equipped with air preheaters. There appears to be no difference between NO_x emissions of firetube boilers and those of small single burner watertube boilers without air preheat.

All of the combustion modifications applicable for oil-fired units are also applicable to boilers burning natural gas. Table 2-9 summarizes the available information on the performance, applicability and availability of these techniques for gas-fired units.

The following subsections highlight the major points of interest for each of the techniques considered.

2.4.1 Low Excess Air (LEA)

Implementation of LEA firing on gas-fired units is similar to that on oil-fired units because the boiler equipment is essentially the same. Low excess air reduces NO_x emissions approximately 12 percent for firetube boilers, 8 percent for watertube boilers, without preheated air and about 15 percent for watertube boilers with preheated air. Test data also shows that excess oxygen level could in general be reduced to around 3.0 percent without excessive emissions of CO or HC (References 2-4 and 2-20 and 2-53).

TABLE 2-8. BASELINE NO_x EMISSION FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS

Type of Boiler	Number of Boilers	Excess O_2 (Weighted Average)	Range of NO_x Emissions ng/J (Weighted Average)	Range of NO_x Emissions lb/10^6 Btu (Weighted Average)
Firetube	8	3.6 - 11.5 (6.5)	28.6 - 55.1 (41)	0.066 - 0.128 (0.095)
Watertube without air preheat	9	2.9 - 8.9 (5.3)	30.1 - 97.9 (47)	0.070 - 0.228 (0.116)
Watertube with air preheat	11	1.9 - 13.1 (5.7)	49.0 - 190.1 (113)	0.114 - 0.444 (0.263)

T-1754

TABLE 2-9. COMBUSTION MODIFICATION NO_x CONTROLS FOR GAS-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commerical Availability/ R&D Status	Comments
Low Excess Air (LEA)	Reduction in air-fuel ratio by reducing air flow to the windbox	28	5 to 35	Generally excess O_2 can be safely reduced to 3.0%. This reduction represents a 2.5% drop from baseline.	Method and control equipment currently available.	Generally practiced because of increased boiler efficiency. Best NO_x reductions reported for large multiburner units.
Staged combustion air (SCA)	Injection of secondary air downstream of the burner(s) in the direction of the flue gas path	3	5 to 46	70-90% burner stoichiometries can be maintained. Applicable to all units, however requires extensive equipment modification.	Technique is still experimental especially for small firetube and watertube units.	Found to be less effective on firetube boilers than watertube boilers. Generally less effective for gas-fired units.
Burners out of Service (BOOS)	One or more burners on air only. Remainder firing fuel rich.	3	17 to 44	Applicable only to multiburner units. Best suited for square burner pattern.	Technique is available. Retrofit application only. Requires careful selection of BOOS and control of air flow.	May require modification of gas delivery system and burners to avoid derating.
Flue Gas Recirculation (FGR)	Recirculation of flue gas to the burner windbox. Requires motor, fan and connecting ducting.	3	48 to 86	Flue gas recirculation rates possible up to 45%. Technique is applicable to all boiler types except ones equipped with ring burners	Available now. Best suited for new boilers. Retrofit application would result in extensive burner modifications.	Flame instability problem is not severe except for ring burners. Minor burner modifications can guarantee stable flames. Most effective on watertube units.
Staged combustion and Flue Gas Recirculation (FGR)	Combined techniques of staged combustion air and FGR	1	76	Applicable to all boilers with some restrictions as individual techniques.	FGR is an available technique. SCA for small package units is still at R&D stage.	No added benefit of SCA to FGR performance. Combined methods are not additive in their effect.

Continued

T-1755

TABLE 2-9. CONCLUDED

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commerical Availability/ R&D Status	Comments
Load Reduction (LR)	Reduction of both fuel and air flow to burners. Or design with enlarged firebox.	21	32% decrease to 82% increase in (10.5% average reduction)	Tests to 20% of rated capacity. Applicable to all units.	Technique available. However, retrofit application is not feasible due to initial low load factor of industrial units.	Least effective on firetube boilers because of lower combustion intensity. Applicable for new watertube units with increased firebox size.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater.	2	20-55 ng/J^{-1}/ temperature per 50K reduction in air temp.	Applicable only on units equipped with air preheaters (large watertube units). This application is very limited.	Technique available but not implemented because of significant loss in efficiency.	Implementation would require other designs to recover loss of heat. Technique is not desirable because of loss in efficiency.
Low NO_x Burners (LNB)	New burner designs with controlled air/ fuel mixing and increased heat dissipation.	N/A	20-50	New burners generally applicable to all boilers. More information is needed.	Commercially offered but not demonstrated	Specific emissions data from industrial boilers equipped with LNB are lacking.
Ammonia Injection	Injection of NH_3 as a reducing agent in the flue gas.	5 (4 Japanese, installations, 1 domestic)	40-70	Applicable for large package and field-erected watertube boilers. Not cost effective for firetube boilers because of size.	Commercially offered but not demonstrated	Should be fewer problems than with coal- or oil-firing technique very costly.

T-1755

In summary, LEA is not a uniformly effective NO_x control technique for gas-fired boilers. However, combustion with LEA remains desirable because of increased boiler efficiency.

2.4.2 Staged Combustion Air (SCA)

Staged combustion air on gas fired boilers is applied in the same manner as on oil-fired boilers. The firetube and single burner watertubes for which SCA was implemented with oil firing were also used to investigate the effectiveness of the technique for gas firing. SCA on gas-fired multiburner watertubes was also investigated implementing the BOOS technique. The following sections summarize the performance, applicability and availability of the various methods of implementing SCA on the major gas-fired industrial boilers.

2.4.2.1 Firetube Boilers

A schematic of the staged air injection system for firetube boilers is shown in Figure 2-7. In the EPA study, NO_x emissions were reduced 25 percent at a burner stoichiometry of 90 percent and overall excess air of 2.9 percent (Reference 2-53). Secondary air was most effective when injected downstream of the burner at a distance equivalent to 1.5 firebox diameters.

As in the case for oil-fired firetubes, more testing is needed to assess the feasibility of this technique. The probable high cost both as a retrofit and a new boiler design feature associated with the modest NO_x reductions make SCA unattractive for gas-fired firetube boilers.

2.4.2.2 Packaged Watertube Boilers

NO_x emissions from the "D" type watertube boiler (Figure 2-9) with staged combustion averaged 6 percent of baseline levels. The optimum location of the injected air was found to be at a distance of at least 1.2 m (4 feet) from a gas gun burner. Only marginally better NO_x reduction was achieved by increasing this distance to 2.1 m (7 feet) (References 2-20 and 2-55).

NO_x reductions for the other single burner watertube boiler (Figure 2-8) averaged only approximately 30 percent when the secondary air was injected at approximately 1 m (3 feet) and 3 m (9 feet) from the burner exit plane. Injection of secondary air between 1 and 3 meters from the ring burner caused only a slight reduction in NO_x emissions (References 2-20 and 2-55).

Staged combustion was less effective for the second watertube boiler because the combustion air was preheated. The high preheat temperatures reduced the effectiveness of SCA in lowering thermal NO_x. When the primary combustion air temperature was reduced, NO_x emissions were reduced 69 percent with staged air injection (Reference 2-55). This indicates that NO_x emissions from gas-fired boilers are more sensitive to combustion air temperature than oil-fired boilers.

The same study also indicated that the type of gas burner -- gun or ring -- influenced the location of the secondary injection air for optimum NO_x reductions. For the gun type burner, NO_x emissions decreased as the air was injected further away from the burner exit plane. This reduction levels off at a distance corresponding to approximately 7 cm per thousand Joules of heat input. For the ring type burner, NO_x reduction peaked at two staged air injection locations: 0.8 and 3.0 meters approximately. These distances correspond to approximately 2 and 7 cm per thousand Joules of heat input respectively. Thus, for the ring burner, it seems that the staged air could also be injected much closer to the burner with similar NO_x reduction results (References 2-20 and 2-55).

Staged combustion air for small gas-fired watertube boilers is still at the experimental stage. If ever developed for these units, SCA will be used with new units burning oil instead of gas because the technique is more effective for the liquid fuels containing nitrogen. More pilot and field studies are necessary to confirm some of the trends described above to define safe operating limits of the technique when the boiler is operating at various loads.

2.4.2.3 Multiburner Watertube

Staged combustion can be implemented on multiburner units by utilizing secondary air ports or by the BOOS method. For gas-fired boilers BOOS reduced NO_x emissions to a maximum of 30 percent by terminating the fuel flow to half of the available burners (Reference 2-20).

As in the case with oil firing the optimum BOOS selection varies for all existing boilers. Similarly, limitations such as boiler derate when many burners are set on air only are also applicable to gas-fired units as for oil-fired units. Operational impact such as corrosion and soot formation are very much reduced with gas-fired boilers.

2.4.3 Flue Gas Recirculation (FGR)

Three natural gas-fired boilers were retrofitted with FGR, two by Ultrasystems (Reference 2-53) and the third by KVB (References 2-20 and 2-55). Figures 2-10 through 2-12 show schematics of the FGR system in two applications. In all cases the burner windbox was breached to install the FGR duct. The recycled flue gas was mixed with both primary and secondary air.

The firetube boiler has a gas "ring" burner embedded in the refractory throat (see Figure 2-23). Apparently, this burner permitted flue gas recirculation rates up to 55 percent without flame instability. Nitrogen oxide reductions were approximately 50 percent for 25 percent FGR and 70 percent for 50 percent FGR. Excess carbon monoxide emissions reached significant levels only at very low (less than 1.5 percent) excess O_2 levels (Reference 2-53).

For the 73 MW (250×10^6 Btu/hr) "D" type boiler, NO_x reductions on the order of 70 percent were achieved with FGR rates as high as 45 percent. Flame stability could apparently be maintained with the typical gas fired "ring" burner installed in this watertube unit. Figure 2-24 shows a schematic of the burner (Reference 2-53).

The third package watertube boiler retrofitted with FGR was a 5 MW "D" type unit equipped with a ring burner similar to the one shown in Figure 2-24. Installation of FGR caused severe flame stability problems even at low recirculation rates. These problems were alleviated by using a gas gun burner instead of the ring type. However, flue gas recirculation rates were still limited to 20 percent. Using the gas burner, NO_x emissions were reduced 52 percent with 8 percent FGR and 75 percent with 20 percent FGR (Reference 2-55).

There seems to be no clear trend between gas burner type and flame stability with FGR. However, it is evident that FGR installation will necessitate, in most cases, extensive burner modifications to alleviate the flame instability. There is some indication that the burner shown in Figure 2-23 may not require any modification.

Flue gas recirculation for gas-fired industrial boilers is definitely available and is an effective technique. However, use of FGR may necessitate use of different burner configuration.

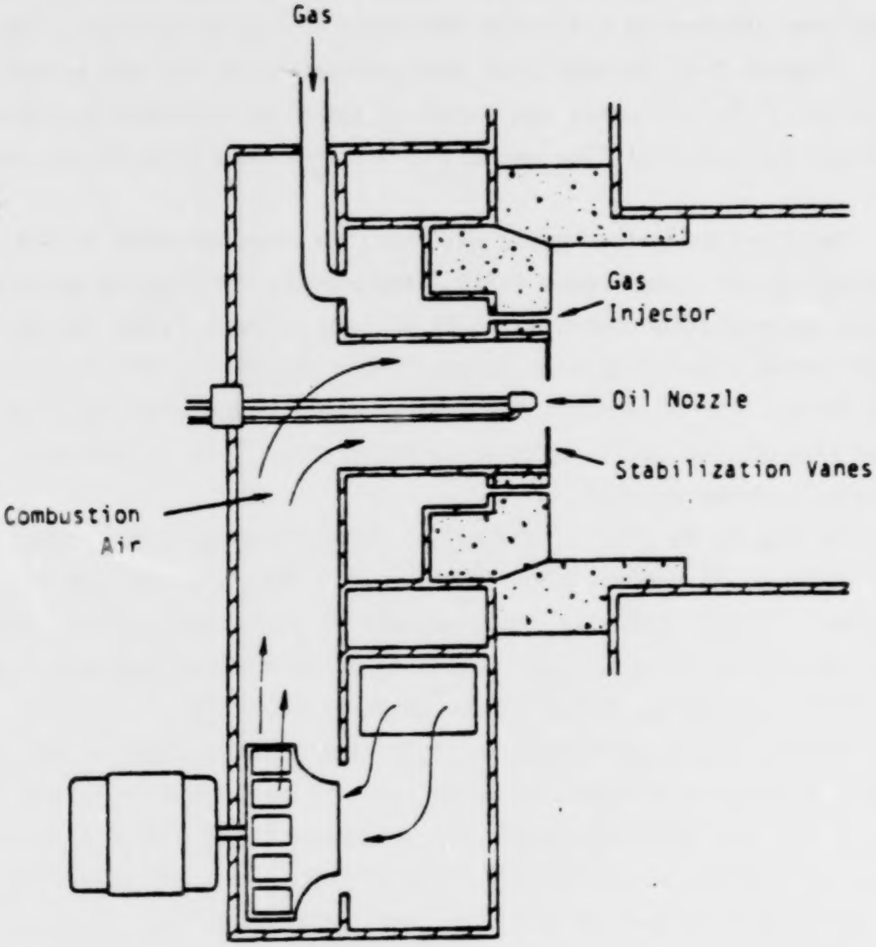


Figure 2-23. Schematic of the windbox burner arrangement of a firetube burner (Reference 2-53).

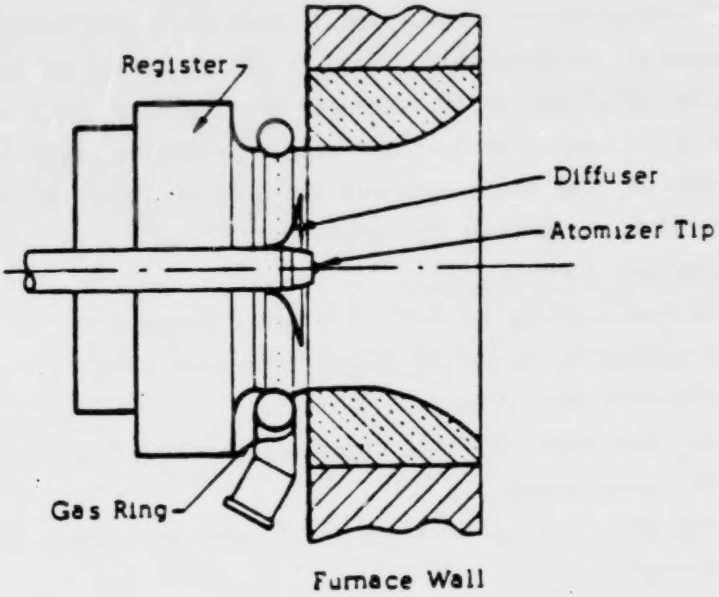


Figure 2-24. Schematic of register burner installed in a watertube boiler (Reference 2-53).

2.4.4 Combined Flue Gas Recirculation and Staged Combustion

Data for natural gas are limited to only one boiler, the 5 MW (17.5×10^6 Btu/hr) "D" type packaged unit retrofitted with FGR and SCA in an EPA Test Program (References 2-20 and 2-55). These data indicate that the addition of staged air injection does not further decrease NO_x emissions beyond the levels achieved with FGR (76 percent).

The combined FGR and SCA does not present any operational impact in addition to those caused by the single application of either technique. There is no incentive in adding SCA to FGR when there is no additional NO_x reduction.

2.4.5 Load Reduction

Load reduction gave an average NO_x emission reduction of 3.4 percent for firetubes; 6.4 percent for watertube boilers without air preheaters and 35 percent for boilers with air preheat (References 2-20 and 2-55). In these latter cases, with air preheat, the reduction in boiler load also produced a reduction in combustion air temperature.

In general, reduced boiler load is not as effective for gas-fired boilers as for oil-fired units. Reduced heat release rates via larger firebox design or new units does not appear promising based on these results. Reduced load often requires the need of increased O_2 which virtually negates any drop in NO_x emissions.

2.4.6 Reduced Air Preheat (RAP)

Measurements of the effects of windbox temperature on gas-fired boilers were conducted in an EPA study (Reference 2-20). The following general conclusions were drawn:

1. NO_x emissions decrease significantly with reduced combustion air temperature
2. The effect of air temperature is more pronounced for larger burners
3. The overall thermal efficiency of the boiler is reduced, with reduced air preheat

Reduction of combustion air temperature is a very effective NO_x control technique for gas-fired boilers. Emissions were reduced 20 ng/J for each 50K reduction in combustion air temperature for two watertube boilers.

The application of RAP is limited to boilers equipped with air preheaters. These units are all of the watertube design type and are usually greater than 15 MW of heat input (50×10^6 Btu) (Reference 2-20). Overall efficiency of the unit may be maintained by adding an economizer (Reference 2-59).

2.4.7 Low NO_x Burners (LNB)

Available low NO_x burners are applicable on gas-fired as well as oil-fired boilers. Detailed performance data of the burners described in Section 2.3.7 are very limited for natural gas combustion.

The good mixing and divided flame burners which primarily reduce thermal NO_x could perform better with natural gas combustion. However, no data are available to quantify this.

Since the oil-fired LNB can also operate with natural gas, this NO_x control technique can be considered commercially available. However, the commercialization has been limited to Japanese installations.

Continuing research and development effort in U.S. is directed primarily toward oil-fired burners. Commercial application of these burners is targeted for late 1979 and beyond.

2.4.8 Ammonia Injection

The design and application of the ammonia injection process does not vary significantly with the fuel burned. Therefore, the basic design of the injection system shown in Figure 2-5 for a coal-fired watertube boiler is also applicable to gas-fired boilers. Application to the smaller firetube units would be similar to that of Figure 2-22, as discussed in Section 2.3.8 for oil-fired units.

The ammonia injection process is easier to operate and maintain with gas firing. This advantage is due primarily to the less severe flue gas environment from combustion of natural gas. For example, the absence of sulfur oxides eliminates the possibility of sulfate formation with unreacted ammonia. In addition, the absence of particulate emissions will reduce the maintenance of the injection grid to remove accumulated deposits. Finally, gas-fired boilers do not produce water wall deposits like those in coal- and residual oil-fired boilers and thus the fluctuation in flue gas temperatures caused by these deposits is eliminated.

Ammonia injection is a control technology which is commercially offered but not demonstrated. The effectiveness varies from 40 to 70 percent NO_x reduction depending on the application (Figure 2-21). As in the case of oil-fired units, ammonia injection will probably not be suitable for small units such as firetubes and package watertubes because of the significant incremental cost to the equipment and to its operation. In addition, many small units operate at continuously changing loads depending on plant steam demand. The variation in load will cause temperature fluctuations which degrade the performance of the process.

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SECTION 3

CANDIDATES FOR BEST SYSTEMS OF EMISSION REDUCTION

This section identifies and discussed alternative combustion modification control techniques capable of achieving moderate, intermediate, and stringent levels of NO_x control. These control levels are based on uncontrolled baseline emission levels and the capabilities of combustion modification controls. Candidate systems of emission reduction may involve either single or combined applications of the techniques characterized in Section 2. The selection of candidate control systems for each industrial boiler/fuel category was based on an assessment of the effectiveness, commercial availability or R&D status, operational impact and reliability of each control system. Energy, environmental, and cost impacts are also considered; however detailed evaluation is deferred to later sections of this report.

3.1 CRITERIA FOR SELECTION

In selecting the best system of NO_x emission reduction, many factors have to be considered, including

- Control effectiveness and applicability
- Reliability and availability
- Process impacts
- Environmental impacts
- Capital and operating costs, including energy impacts

The effectiveness of controls in reducing NO_x emissions, and their applicability to industrial boilers as well as their reliability, were used to select preliminary candidate control systems. Techniques were considered if they were expected to be available for new boilers sold in 1983 or sooner (Reference 3-1). Performance data for these preliminary candidates were than carefully reviewed to identify any demonstrated or expected process or environmental impacts. For example, major impacts such as severe derating of the boiler can make a control option no longer viable. Environmental impacts were evaluated through the analysis of measured or postulated incremental emissions, other than NO_x, when controls are implemented. Finally, capital and operating costs, including energy impacts, were considered. These costs were used to decide between favorable alternative control options, or in the case of costly but highly effective techniques, to defer application until stringent control levels are absolutely necessary.

All of the above listed factors were considered by evaluating detailed field test results when available and through discussions with major equipment manufacturers and users, and control R&D groups.

In the ensuing discussion of emission control technologies, candidate technologies were compared using three emission control levels labelled "moderate, intermediate, and stringent." These control levels were chosen only to encompass all candidate technologies and form bases for comparison of technologies for control of specific pollutants considering performance, costs, energy, and environmental effects.

From these comparisons, candidate "best" technologies for control of individual pollutants are recommended for consideration in subsequent industrial boiler studies. These "best technology" recommendations do not consider combinations of technologies to remove more than one pollutant and have not undergone the detailed environmental, cost, and energy impact assessments necessary for regulatory action. Therefore, the levels of "moderate, intermediate, and stringent" and the recommendation of "best technology" for individual pollutants are not to be construed as indicative of the regulations that will be developed for industrial boilers. EPA will perform rigorous examination of several comprehensive regulatory options before any decisions are made regarding the standards for emissions from industrial boilers.

Two factors were primarily considered in selecting these levels of control. The first criterion is the baseline uncontrolled emission level for each industrial boiler/fuel category. The second is the recorded or estimated NO_x reduction effectiveness of each combustion modification control. Careful consideration of the uncontrolled baseline NO_x level and the percent reduction in emissions that is attributable to selected control systems determines the degree of control.

Baseline emission factors are extremely important because they ultimately determine what control levels are achievable and which control are appropriate. For example, if a conservative or high baseline emission level is used, then the selected control levels based on reported NO_x reduction will also be conservative and easier to obtain. On the other hand, if a low baseline NO_x level is used, a selected moderate control level may prove difficult to achieve. As a review of the limited emission data will show (see Section 7), baseline (and controlled) emissions levels were quite variable in some cases and well defined in other cases. So the general caution is that the baseline (and controlled) emission levels should be considered only tentative because of the limited data. However, it should be noted that the moderate control levels suggested here for the boiler/fuel catergories considered are generally conservative in the sense that demonstrated control techniques have, in specific instances, achieved controlled NO_x levels lower than the suggested moderate levels.

Table 3-1 lists the baseline NO_x emission factors selected after review of all available data. The table also compares these selected levels to the previously suggested emission factors (Reference 3-29) contained in EPA Document AP-42 (Reference 3-2). Emissions data for pulverized coal-fired industrial boilers are limited to six units (References 3-3 through 3-5). These emissions ranged from 174 ng/J to 563 ng/J and the size of the units ranged from 47 MW to 147 MW (160 to 500 x 10^6 Btu/hr) of heat input[a]. There was no general correlation between NO_x emission levels and boiler size/type or coal characteristics.

The NO_x emission levels given in AP-42 (Reference 3-2) for coal-fired stokers consist of only one number (273 ng/J) which was derived from data on spreader stokers only. That number is in good agreement with the NO_x baseline level (265 ng/J) selected in this study for spreader stokers, as shown in Table 3-1. However, the AP-42 number is in very poor agreement with the reported averages for the underfeed and the chain grate

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[a] Note: NO_x emission data dicussed in this report are all listed in Section 7, along with boiler and fuel characteristics.

TABLE 3-1. COMPARISON OF BASELINE NO_x EMISSION LEVELS

Fuel	Boiler Type	Typical Size (Heat Input Capacity) MW(10^6 Btu/hr)	No. of Boilers Tested	Average NO_x Baseline Emission Level ng NO_2/J(lb/10^6 Btu)	AP-42 (Ref. 3-2) NO_x Baseline Emission Level ng NO_2/J(lb/10^6 Btu)	Sources of Data Used for Selected Baseline Emissions
Pulverized Coal	Single Wall and Tangential	59(200) 114(400)	4 2	285(0.663) 285(0.663)	328(0.763) 328(0.763)	Ref. 3-3, 3-4, 3-5 Ref. 3-3, 3-4, 3-5
Stoker Coal	Spreader	44(150), 25(85)	7,5	265(0.616)	273(0.635)	Ref. 3-2 through 3-6
	Underfeed	9(30)	2	150(0.349)	273(0.635)	Ref. 3-3
	Chain Grate	22(75)	2	140(0.326)	273(0.635)	Ref. 3-4, 3-5
Residual Oil[a]	Firetube	4.4(15)	5	115(0.267)	--	Ref. 3-3, 3-4, 3-8
	Watertube	8.8(30)	10	160(0.372)	171(0.398)	Ref. 3-3, 3-4, 3-8, 3-9
	Watertube	44(150)	7	160(0.372)	171(0.398)	Ref. 3-3, 3-4
Distillate Oil	Firetube	4.4(15)	6	75(0.175)	68(0.158)	Ref. 3-3, 3-4
	Watertube	29(100)	4,3	55^b, 90^c(0.128^b, 0.209^c)	--	Ref. 3-3, 3-4, 3-9
	Watertube	44(150)	1	90^c(0.209^c)	--	Ref. 3-3, 3-4
Natural Gas	Firetube	4.4(15)	8	40(0.093)	75(0.174)	Ref. 3-3, 3-4, 3-10
	Watertube	29(100)	9,11	45^b, 110^c(0.105^b, 0.255^c)		Ref. 3-3, 3-4, 3-9
	Watertube	44(150)	7	120^c(0.280)^c	--	Ref. 3-3, 3-4

[a] Includes No. 5 and No. 6 fuel oils.
[b] From boilers not equipped with air preheaters.
[c] From boilers equipped with air preheaters.

units. This stands to reason as spreader stokers are known to be higher NO_x emitters than underfeed units (Reference 3-3). This study incorporates new data made available since Document AP-42 and updates were published.

All other selected NO_x baseline emission data generally agree with the AP-42 emission levels except that for natural gas-fired firetube boilers which show a difference of 35 ng/J. This disparity is due to two reasons. The first is that Document AP-42 gives a range for natural gas-fired firetube boilers and the final value chosen by that document is from the high end of that range. The second reason is that the AP-42 emission factor is derived from a more limited data base than that reviewed in this study. This, as well as other emission data, is well documented in Section 7 of this report.

The NO_x emission factors selected in this study agree with the results for industrial boilers from a recent study to update EPA Document AP-42 emission factors (Reference 3-14).

In addition to the original seven standard boiler/fuel categories recommended by PEDCo (Reference 3-28), three other categories were considered: residual oil-fired firetube boilers and distillate oil- and gas-fired watertube boilers. Furthermore, for the latter two categories, a distinction was made between boilers equipped with air preheaters and those that are not. The baseline NO_x emissions for these three additional categories are clearly different from the original seven; therefore they should be treated separately when assessing the feasibility of reducing emissions to a predetermined control level. Finally, four additional size variations of the above 10 standard boiler/fuel categories were requested by EPA to further aid in the economic assessment of controls, bringing the total boiler/fuel cases treated to 14 (Reference 3-32).

With the baseline emission levels of each industrial boiler/fuel category established (to the extent possible as limited data permitted), the capabilities of the available control techniques were carefully reviewed to select the best control options and establish achievable control levels. Tables 3-2 through 3-5 summarize the performance of the candidate control systems for pulverized coal-, stoker coal-, residual oil-, distillate oil-, and gas-fired boilers, respectively. These

TABLE 3-2. CANDIDATES FOR BEST SYSTEMS OF NO_x EMISSIONS REDUCTION: PULVERIZED COAL-FIRED BOILERS

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact	Availability
Low Excess Air	5 - 25	Increased boiler efficiency.	Increased efficiency offsets capital and operating costs.	Possible increased CO and organic emissions.	Available
Overfire Air	5 - 30	Possible increased slagging, corrosion. Perhaps slight decrease in boiler efficiency.	Major modification. Marginal increase in cost for new units.	Possible increased particulate and organic emissions.	Commercially offered but not demonstrated for this boiler/fuel category
Reduced Combustion Intensity	5 - 25	None. Best implemented as increased furnace plan area in new designs.	Major modification. Marginal increase in cost for new units.	None	Technology transfer required from utility industry
Low NO_x Burners	45 - 60	None expected.	Potentially most cost-effective.	None expected.	1981 - 1983[c]
NH_3 Injection	40 - 60	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modifications.	Possible emissions of NH_3 and byproducts.	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied.

[c] References 2-79, 3-30

TABLE 3-3. CANDIDATES FOR BEST SYSTEMS OF NO_x EMISSIONS REDUCTION: STOKER COAL-FIRED BOILERS

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact	Availability
Low Excess Air	5 - 25	Possible grate overheat, clinker formation, increased corrosion. Close operator attention required.	Increased efficiency should partially offset costs.	Possible increased CO, organic, and particulate emissions.	Available
Overfire Air	5 - 25	Possible grate overheat, clinker formation, increased corrosion. Close operator attention required. Perhaps slight decrease in boiler efficiency.	Major modification of grate and OFA, probably costly. Present units have OFA for smoke control only.	Possible increased CO, organic, and particulate emissions.	R&D
NH_3 Injection	40 - 60	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modifications.	Possible emissions of NH_3 and byproducts.	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly.

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied.

TABLE 3-4. CANDIDATES FOR BEST SYSTEMS OF NO_x EMISSIONS REDUCTION: RESIDUAL OIL-FIRED BOILERS

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact	Availability
Low Excess Air	5 - 20	Increased boiler efficiency.	Increased efficiency partially offsets costs.	Possible increased CO and organic emissions.	Available
Staged Combustion	20 - 40	Perhaps slight decrease in boiler efficiency.	Major modification, perhaps costly.	Possible increased particulate and organic emissions.	Commercially offered but not demonstrated for this boiler/fuel category
Low NO_x Burners	20 - 50	None expected.	Potentially most cost-effective.	None expected.	Commercially offered but not demonstrated
NH_3 Injection	40 - 70	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modification.	Possible emissions of NH_3 and byproducts.	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly.

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied.

TABLE 3-5. CANDIDATES FOR BEST SYSTEMS OF NO$_x$ EMISSIONS REDUCTION: DISTILLATE OIL- AND GAS-FIRED BOILERS

Technique	Effectiveness[a] (% NO$_x$ Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact	Availability
Low Excess Air	5 - 15 (oil), 5 - 10 (gas)	Increased boiler efficiency.	Increased efficiency should offset some of costs.	Possible increased CO and organic emissions.	Available
Staged Combustion	20 - 40 (oil), 25 - 45 (gas)	Perhaps slight decrease in boiler efficiency.	Major modification, probably costly.	Possible increased organic emissions.	Commercially offered but not demonstrated for this boiler/fuel catetory
Flue Gas Recirculation	40 - 70 (oil) 45 - 75 (gas)	Possible flame instability. Can be eliminated with proper engineering/testing.	Major modification, probably costly.	Possible increased organic emissions.	Available
Reduced Air Preheat	20 - 55 (oil) 20 - 55 (gas)	Replacing air preheater with economizer in new designs.	None, other than engineering redesign of new units (if necessary).	None	Available
Low NO$_x$ Burners	20 - 50	None expected.	Potentially most cost-effective.	None expected.	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly.

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied.

candidate systems are the result of the preliminary review in Section 2. Table 3-6 summarizes suggested emission levels for moderate, intermediate, and stringent control.

For moderate control levels the NO_x reduction required from baseline emissions varies from approximately 5 to 20 percent, depending on the boiler/fuel category. For example, in the case where fully demonstrated and commercially available control systems could only reduce NO_x emission by 5 percent, this reduction was used to establish the moderate control level. However, if the demonstrated and commercially available control system was very effective in reducing NO_x by 20 percent without foreseeable operational problems, this reduction was used in selecting the moderate control level. For example, by replacing air preheaters with economizers on new watertube boilers firing natural gas, the NO_x emissions may be reduced at least 20 percent from the average baseline level of 110 ng/J.

For intermediate control levels, the NO_x reduction required from baseline emissions varies from approximately 20 to 40 percent. Control systems include both commercially available and developing combustion modification techniques. For example, new pulverized coal-fired boilers can operate with staged combustion using overfire air ports thus reducing NO_x emissions 20 to 30 percent from the respective baseline levels. An example of developing technology for intermediate control of residual oil-fired boilers would be low NO_x burners.

For stringent control levels, the NO_x reduction required from baseline emissions varies up to approximately 60 percent. Often the same control system which is capable of achieving the intermediate control level can also achieve the stringent level by simply increasing the degree of control. For example, flue gas recirculation (FGR) can reduce NO_x emissions up to 75 percent for natural gas combustion by increasing the FGR rate up to 40 percent (References 3-4, 3-8 and 3-9). In some cases, the stringent control level requires technology still under development, such as ammonia injection for residual oil-fired watertube boilers. Occasionally the control system capable of achieving drastic NO_x reductions combines two or more combustion modification techniques. For

TABLE 3-6. SUGGESTED NO_x CONTROL LEVELS FOR INDUSTRIAL BOILERS

Fuel	Control Level, ng NO_2/J (lb $NO_2/10^6$ Btu)		
	Moderate	Intermediate	Stringent
Coal: Units $\geq$29 MW Heat Input[a]	301 (0.7)	258 (0.6)	215 (0.5)
Coal: Units <29 MW Heat Input	215 (0.5)	172 (0.4)	129 (0.3)
Residual Oil	129 (0.3)	108 (0.25)	86 (0.2)
Distillate Oil and Gas	86 (0.2)	65 (0.15)	43 (0.1)

[a] It is suggested that spreader stokers be placed at these moderate, intermediate, and stringent levels, regardless of heat input capacity.

example, reduced air preheat and FGR are required for distillate oil- and gas-fired watertube boilers with air preheaters.

The following sections discuss the alternative NO_x emission control systems for industrial boilers necessary to reduce emissions to the three levels of control. For each boiler/fuel category, the best candidate NO_x control systems are identified for the moderate, intermediate, and stringent control levels.

3.2 CANDIDATE CONTROL SYSTEMS FOR COAL-FIRED INDUSTRIAL BOILERS

NO_x formation from coal combustion is primarily from fuel NO_x. In fact, laboratory studies under controlled operating conditions have shown that fuel NO_x can account for up to 80 percent of the total NO_x from combustion of coal (Reference 3-11). In principle, the best strategy for fuel NO_x abatement combines low excess air firing, optimum burner design, and staged combustion.

Tables 3-7 and 3-8 list the candidates for best control system for coal-fired industrial boilers with heat inputs greater than and less than 29 MW (100×10^6 Btu/hr) heat input, respectively. These control systems were selected from the candidates summarized in Tables 3-2 and 3-3. Coal-fired units are divided at 29 MW (100×10^6 Btu/hr) heat input since the larger units tend to have higher NO_x emissions levels. Pulverized coal-fired boilers and spreader stokers are generally larger than 29 MW (100×10^6 Btu/hr) of heat input (References 3-3, 3-11). However, spreader stoker units smaller than 29 MW are not uncommon. Underfeed and chain grate stokers generally have heat input capacities of less than 29 MW, and generally produce lower NO_x emission levels than the larger spreader stokers and pulverized coal units. Cyclone boilers have not been included since sales of these units have halted since 1974 (Reference 3-31). Their baseline NO_x emisions are extremely high (approximately 650 ng/J, 1.51 lb/10^6 Btu), and not easily amenable to control (Reference 3-13).

The following subsections present the criteria for selecting the control systems presented in Tables 3-7 and 3-8 and the order in which they were selected. Each subsection pertains to the individual boiler equipment type identified.

TABLE 3-7. BEST CONTROL SYSTEMS FOR COAL-FIRED INDUSTRIAL BOILERS WITH HEAT INPUT $\geq$ 29 MW (100 x 10^6 Btu/Hr)[a]

Boiler Equipment Type	Baseline NO_x Emissions ng/J (lb/10^6 Btu)	Level of Control		
		Moderate 301 ng/J (0.7 lb/10^6 Btu)	Intermediate 258 ng/J (0.6 lb/10^6 Btu)	Stringent 215 ng/J (0.5 lb/10^6 Btu)
Pulverized Coal-Fired	285 (0.663)[b]	No control necessary[c]	1. Low excess air 2. Overfire air	1. Overfire air* 2. Low NO_x burner*** 3. Ammonia injection[d]**
Spreader Stoker	265 (0.616)	No control necessary	Low excess air	Low excess air/ Overfire air***

T-1759

[a] Low excess air operation is recommended practice whenever controls are required. However combination of LEA and OFA is not recommended for pulverized coal tangential units (see Section 3.2.1.2).

[b] Wide range of baseline emissions reported (see Section 3.2.1.1)

[c] Some units may require low excess air.

[d] NH_3 injection required only for those units with unusually high baseline emissions.

*Commercially offered but not demonstrated for this boiler/fuel category.

**Commercially offered buy not demonstrated.

***Under research and development.

TABLE 3-8. BEST CONTROL SYSTEMS FOR COAL-FIRED INDUSTRIAL BOILERS WITH HEAT INPUT <29 MW (100 x 10^6 Btu/Hr)

Boiler Equipment Type	Baseline NOx Emissions ng/J (lb/10^6 Btu)	Level of Control		
		Moderate 215 ng/J (0.5 lb/10^6 Btu)	Intermediate 172 ng/J (0.4 lb/10^6 Btu)	Stringent 129 ng/J (0.3 lb/10^6 Btu)
Spreader Stoker	265(0.616)	Low excess air/overfire air***	Ammonia injection**	Ammonia injection**
Chain Grate	140(0.326)	No control necessary	No control necessary	Low excess air
Underfeed	150(0.349)	No control necessary	No control necessary	Low excess air

**Commercially offered but not demonstrated.
***Under research and development.

3.2.1 Pulverized Coal-Fired Boilers

Industrial size pulverized coal-fired boilers can be subdivided into two categories based on the firing mode of the burners in the furnace: tangential and single wall firing. No significant differences in NO_x emission levels were observed between these two firing types (see Section 7) although recent data indicate a difference in NO_x emissions for utility size units of these two firing types (References 3-14 and 3-15).

As stated earlier, information on baseline as well as controlled NO_x emissions from pulverized coal-fired industrial size boilers is very limited. Therefore the selection of the applicable control systems for each of the three control levels relied heavily on utility boiler experience with combustion modifications (Reference 3-13).

3.2.1.1 Moderate Control Level

No control should be necessary to achieve the moderate control level of 301 ng/J as the selected baseline NO_x emission level is 285 ng/J. The moderate control level was set at 301 ng/J and not any lower because of the broad range in baseline NO_x emissions for the six units tested, ranging from 174 to 563 ng/J with most data between 201 and 296 ng/J, yielding an average baseline of 285 ng/J. No significant correlation of emission levels with boiler type or size or coal characteristics were evident from a review of the data presented in Table 7-2 (see Section 7).

3.2.1.2 Intermediate Control Level

Combustion modifications capable of reducing NO_x emission from 285 to the intermediate control level of 258 ng/J (10 percent reduction) include low excess air and overfire air. Low excess air (LEA) operation should be capable of achieving the intermediate control level in all but a few cases. Overfire air (OFA) should satisfy the remaining cases. Combination of LEA with OFA has been known to reduce NO_x emissions from utility boilers by 30 percent; however it is not recommended for tangential boilers (Reference 3-13). Combustion Engineering, the manufacturer of tangential boilers, recommends using normal overall furnace excess air levels with OFA operation to ensure no coincident increase of unburned carbon in the flyash or carbon monoxide emissions from their units (References 3-33 and 3-34).

The LEA and OFA control system has the primary advantage over the other control systems because of its commercial availability and its effectiveness. The cost of the system is not prohibitive when NO_x ports are designed as a part of new boilers. In addition, careful operation of staged air injection is not expected to seriously affect emissions of other criteria pollutants[a]. Burner stoichiometries in the range of 100 to 110 percent would be adequate to achieve a 20 percent NO_x reduction (Reference 3-15). At these stoichiometry levels the oxidizing atmospheres would prevail in the furnace, thus minimizing concern over possible furnace slagging and boiler tube wastage.

3.2.1.3 Stringent Control Level

Achieving the stringent NO_x emission level of 215 ng/J represents a 25 percent reduction from baseline. Combined low excess air and overfire air operation can achieve this level of control. However, burner stoichiometries would have to be reduced below 100 percent in some cases (Reference 3-13). This low burner stoichiometry level would cause reducing atmospheres in parts of the furnace, thus creating the potential for corrosion of water tubes (Reference 3-13). Generally boiler manufacturers do not recommend burner operation with stoichiometry levels below 100 percent primarily because of increased corrosion potential. Therefore LEA/OFA is recommended as the stringent control technique with the proviso that further field testing and demonstrations may be necessary.

Because of the possible operational problems associated with OFA, low NO_x burners (LNB) were selected as the first backup candidate for achieving the stringent control level. Reported NO_x reductions for utility size units are of the order of 45 to 60 percent (References 3-16 and 3-17). Similar reduction efficiencies are projected for industrial low NO_x burners under development. Therefore LNB is expected to easily meet the 215 ng/J control level, a 25 percent reduction from the average baseline level. Once developed, low NO_x coal-fired burners for industrial boilers could become the candidate control system because of the expected lower cost and other operational advantages over the staged combustion method of OFA. One such burner is being developed by Peabody Engineering Corporation and will be tested by Energy and Environmental Research Corp. (EER) (Reference 3-18).

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[a] The effect of combustion modifications on other criteria pollutants is discussed in Section 6.

If low NO_x burners are not commercialized by 1983, ammonia injection is the alternative stringent control system. Also ammonia injection may be required for those pulverized coal-fired units with unusually high baseline NO_x emissions. However, NH_3 injection is several times more costly than conventional combustion modification controls. In addition, as a developing technology, there are several implementation and operational problems that need to be resolved. The optimal effectiveness for noncatalytic reduction of NO by NH_3 occurs in a very narrow temperature range, approximately 1240 ± 50K (1770 ± 90°F). Hence, precise location of the NH_3 injection ports is crucial. Since the temperature profile in a boiler changes with load, NO_x control with NH_3 may dictate load restrictions on the boiler. Other potential problems include fouling and emissions of NH_3 and byproducts. However, the major strengths of the technique are its potential for high NO_x removal (40 to 60 percent), and its applicability as an additional control that can be combined with conventional combustion techniques for extremely large NO_x reductions (Reference 3-19).

3.2.2 Spreader Stoker Boilers

Field test data of NO_x combustion modifications on spreader stoker fed coal-fired boilers come from four EPA-sponsored programs (References 3-3 through 3-7, and 3-35). The coal in a spreader stoker boiler burns partly in a suspended state and partly on a moving or vibrating grate. The combustion of coal in the suspended state apparently causes NO_x emissions to be generally higher than for other stoker types which feed and combust coal directly on a moving grate. Baseline uncontrolled NO_x emission averaged 265 ng/J for twelve spreader stoker industrial boilers (References 3-3 through 3-7, and 3-35). No significant correlation was observed between NO_x emission levels and unit capacity or fuel properties (e.g., coal type, fuel nitrogen), as a review of the data in Section 7 will show.

Spreader stokers generally range in size from 2.9 MW (10×10^6 Btu/hr) to 146 MW (500×10^6 Btu/hr) heat input

(Reference 3-14). The smaller units, i.e., those under 29 MW (100 x 10^6 Btu/hr), may have to meet stricter control levels than the larger units, according to Table 3-6. The candidate control systems are summarized in Tables 3-7 and 3-8).

Spreader stoker boilers are listed in both Tables 3-7 ($\geq$ 29 MW) and 3-8 (< 29 MW) because this design type is offered over a large range of heat input capacities. However, because their average baseline emission levels are relatively higher than those from other stoker designs, it is recommended that spreader stokers be grouped with pulverized coal units as far as potentially achievable emission control levels are concerned. Spreader stokers are listed together with other stoker types in Table 3-8 solely because of similarities in designs and hence in applicable control techniques.

No control is necessary for meeting the moderate control level of 301 ng/J for spreader stokers larger than 29 MW. The intermediate control level (258 ng/J) may be easily achieved by low excess air (LEA) firing. Operating with LEA would result in increased boiler efficiency. Such problems as grate overheat, clinker formation, and corrosion should be minimized by limiting excess oxygen to 6 percent or more. For stringent control (215 ng/J), LEA and overfire air operation will probably be required. This can be accomplished by reducing undergrate air and increasing overfire airflow through the OFA ports normally installed in stokers. However, close operator attention will be required to avoid the problems of grate overheat, clinker formation, and corrosion associated with firing at too low excess air levels. Presently installed OFA ports were intended only for smoke control. New units should incorporate OFA ports designed for NO_x control. Potential environmental impacts as increased CO, particulate, and organic emissions warrant further testing. To date, LEA and OFA represent the only significant NO_x controls tested on stokers.

According to Table 3-8, smaller spreader stokers (< 29 MW heat input) are faced with stricter control levels, 215, 172, and 129 ng/J (0.5, 0.4 and 0.3 lb/10^6 Btu) for moderate, intermediate, and stringent control, respectively. The moderate level can be met with LEA and OFA. However, the only control option for the intermediate and stringent level is ammonia injection, which as described earlier, is not demonstrated technology for coal-firing. Therefore, it is recommended that spreader stokers, regardless of capacity, be aligned with pulverized coal units as far as potentially achievable control levels are concerned, as illustrated in Table 3-7.

3.2.3 Chain Grate and Underfeed Stokers

Chain grate and underfeed stokers have generally less than 29 MW (100 x 10^6 Btu/hr) heat input capacity. Neither stoker type requires any controls until the stringent level of 129 ng/J is needed. This can be achieved for chain grate (baseline 140 mg/J) and underfeed (baseline 150 ng/J) by reducing the excess air. Tests on new units indicate that NO_x reductions of 10 to 30 percent are possible with low excess air. Hence LEA is the recommended technique (and the only effective technique tested for underfeed stokers).

Stricter levels of control for chain grate and underfeed stokers were not suggested in Table 3-8 because of the very limited number of units tested (two each), and the lack of availability of effective control techniques (besides low excess air operation).

3.3 CANDIDATE BEST CONTROL SYSTEMS FOR RESIDUAL OIL-FIRED INDUSTRIAL BOILERS

Residual oil contains varying amounts of fuel bound nitrogen. During an extensive EPA-sponsored industrial boiler field test program the nitrogen found in residual oils (No. 5 and No. 6) varied from 0.1 to 0.52 percent (Reference 3-4). However, residual oils used in industrial boilers may have nitrogen contents as high as 1.0 percent. Baseline NO_x emissions from boilers burning residual oil are strongly affected by the nitrogen content of the fuel. Boiler design factors such as heat input capacity and combustion air temperature do not affect total NO_x emissions as much as nitrogen content of the oil.

Thus the contribution of fuel NO to total NO_x emissions is comparable to the contribution from thermally generated NO_x. Combustion modification controls which are most effective in reducing fuel NO_x are essentially the same used for coal-fired units. These are primarily low excess air firing and staged combustion. Both these controls limit the oxygen availability in the primary combustion zone, thus reducing the formation of both fuel and thermal NO_x. Table 3-9 lists the best systems of combustion modification for residual oil-fired industrial boilers. These units have been separated into two main categories, firetube and watertube, based on the uncontrolled baseline emission factors. Firetube boilers are generally lower than 9 MW heat input (30 x 10^6 Btu/hr) (Reference 3-12). These units usually have lower combustion intensities than watertube units of the same size, contributing to lower thermal NO formation (Reference 3-8). Baseline NO_x emissions for firetube boilers averaged 115 ng/J while watertube units averaged 160 ng/J.

The following subsections summarize the candidate NO_x combustion modification control systems shown in Table 3-9.

3.3.1 Firetube Boilers

Since baseline NO_x emissions from firetube boilers burning residual oil averaged only 115 ng/J, no controls are generally necessary for these units to meet the moderate control level of 129 ng/J. However, controls are necessary to reduce NO_x emissions to the intermediate and stringent levels of 108 and 86 ng/J respectively.

3.3.1.1 Intermediate Control Level

Since firetube boilers require only a 6 percent NO_x reduction to reach the intermediate level of control (108 ng/J), low excess air firing should easily be adequate. Low excess air operation should also increase boiler efficiency. The same caution about possible increased CO and organic emissions discussed earlier for coal-firing under LEA apply here also.

3.3.1.2 Stringent Control Level

To meet the stringent control level of 86 ng/J, low NO_x burners are the most attractive method of control. Staged combustion has been investigated on one (3.5 MW, 12 x 10^6 Btu/hr) firetube boiler with reductions in NO_x emissions of up to 50 percent (References 3-8 and 3-20). However, staged combustion cannot be easily implemented on these small packaged firetubes, and no feasible air injection system is under development for commercial application.

TABLE 3-9. BEST CONTROL SYSTEM FOR RESIDUAL OIL-FIRED INDUSTRIAL BOILERS[a]

Boiler Equipment Type	Baseline NO_x Emissions ng/J (lb/10^6 Btu)	Level of Control		
		Moderate 129 ng/J (0.3 lb/10^6 Btu)	Intermediate 108 ng/J (0.25 lb/10^6 Btu)	Stringent 86 ng/J (0.2 lb/10^6 Btu)
Firetube	115 (0.267)	No control necessary	Low excess air	1. Low NO_x burners** 2. Staged combustion***
Watertube	160 (0.372)	1. Low excess air 2. Low NO_x burners** 3. Staged combustion*	1. Low NO_x burners** 2. Staged combustion*	1. Low NO_x burners** 2. Ammonia injection**

[a] Low excess air is recommended practice whenever controls are required.

T-1760

*Commercially offered but not demonstrated for this boiler/fuel category.
**Commercially offered but not demonstrated.
***Research and development.

Thus low NO_x burners (LNB) remain as a potentially viable technique. Low NO_x burners reduce NO_x emissions primarily by operating on one of the following principles:

- Controlled mixing (to permit rapid quenching of the flame and reduce residence time at peak flame temperature)
- Divided flame (to provide more rapid cooling of flame)
- Self-recirculation (to dilute combustion gases and reduce peak flame temperature)
- Staged combustion (to reduce available excess oxygen)

As expected from the discussion in Section 2, the self-recirculation and staged combustion burner types are more effective with residual oil (high fuel nitrogen) combustion. Reductions in NO_x ranging from 20 to 50 percent have been reported with commercialized Japanese LNB and experimental domestic LNB. The Kawasaki two-stage combustion type LNB and the LNB being developed by EER, as discussed in Section 2, are two candidate burners for controlling NO_x from residual oil-fired boilers. However, neither burner is presently commercially available. The TRW burner which is commercially offered but not demonstrated may prove to be effective. Note, though, that the heat input capacity per burner of these LNBs may be too large for application to the smaller packaged firetubes. However, they represent potentially the most cost-effective method of high NO_x reduction with little expected adverse operational or environmental impact.

3.3.2 Watertube Boilers

As shown in Table 3-9 the baseline uncontrolled NO_x emissions from packaged and field erected watertube boilers averaged approximately 160 ng/J. The capacity of the boiler and the temperature of the combustion air did not have a significant effect on the baseline emission level (References 3-3, 3-4, 3-9). Combustion modification NO_x controls are necessary to reduce emissions to all three levels of control.

The following subsections discuss the criteria for selecting the control systems listed in order of priority in Table 3-9 for each of the control levels investigated.

3.3.2.1 Moderate Control Level

The moderate NO_x control level of 129 ng/J can be obtained by operating the watertube boiler with a 3 percent excess oxygen level or lower. Section 2 indicated that NO_x emissions were reduced 18 to 23 percent by reducing excess oxygen to the range of 3.1 to 4.2 percent. Achieving the moderate emission level represents a 19 percent reduction.

Operation of watertube boilers with excess oxygen levels in the flue gas on the order of 3 percent is a feasible and demonstrated method of achieving NO_x reductions. The technique has additional advantages such as increased boiler thermal efficiency, reduced fan power requirements and reduced sulfur trioxide formation for both residual oil and coal combustion -- a cause of acid smut emissions, corrosion and fouling (Reference 3-21). Furthermore, low excess air operation also seems to reduce particulate emissions. One EPA study reported approximately 30 percent drop in particulate emissions when burning residual oil (Reference 3-4). Operation at low excess air levels (less than 15 percent) is not favored by industrial boiler operators because of possible smoke emissions during rapid heat changes and possible formation of combustibles with unburned fuel creating a safety hazard. These disadvantages of LEA operation can be avoided by installing controls and implementing a comprehensive maintenance program. The increased costs due to more sophisticated controls and increased maintenance can be balanced by the fuel savings through increased boiler efficiency.

Burner manufacturers currently offer burners that can operate at very low excess oxygen levels (3 to 5 percent). These burners are of the axial flow type. Windbox air distribution is carefully controlled, and low-turbulent air is mixed with the fuel. The carefully controlled air flow eliminates the necessity of high excess air to assure complete mixing and combustion (Reference 3-21).

Alternative control systems include low NO_x burners and staged combustion. Low NO_x burners represent a better alternative for package single burner watertube units because staged air injection is not feasible. The two staged air injection designs presented in Section 2 are considered experimental. In fact, one boiler manufacturer indicated that operation of such a system would be too complicated for a packaged industrial unit (Reference 3-21).

Staged air injection for multiburner field erected watertube boilers might be the next best control system after the LEA technique.

Overfire air injection through NO_x ports is a demonstrated technology and fully capable of achieving 20 percent NO_x reductions. Low NO_x burners for multiple burner industrial size boilers could be undesirable because of possible flame interaction between burners and potential loss in NO_x reduction effectiveness.

In general, LEA is the best candidate NO_x control system capable of achieving 129 ng/J emissions for watertube boilers burning residual oil with a nitrogen content less than 0.5 percent. Of course, higher nitrogen content oils increase baseline emissions, necessitating larger emissions reductions to achieve the moderate control level.

3.3.2.2 Intermediate Control Level

The intermediate control level of 108 ng/J (0.25 lb/10^6 Btu) necessitates reductions greater than 30 percent. Technologies potentially capable of achieving these reductions include low NO_x burners and staged combustion. As in the case for moderate control level, LNB is probably preferred for packaged boilers while overfire air (one form of staged combustion) is preferred for multiburner units. Several low NO_x burner designs are still at the R&D stage; however, full demonstrations and commercialization are expected in the near future. In fact, one manufacturer (TRW) is currently offering an LNB system, with field demonstrations underway or imminent. Overfire air is currently being implemented on utility size units as a staged combustion technique. Since overfire air (OFA) for packaged single burner units has been used only experimentally, its feasibility is questionable.

In general, then, the best candidate NO_x emission control systems for watertube residual oil-fired boilers are low NO_x burners for packaged single burner units and OFA for multiburner boilers. Adverse process and environmental impacts are expected to be minimal; however, these suppositions warrant further verification.

3.3.2.3 Stringent Control Level

NO_x reductions as high as 50 percent have been reported for low NO_x burners and staged combustion control systems (References 3-3, 3-4, 3-8, 3-9, 3-23, and 3-24). The stringent control levels of 86 ng/J (0.2 lb/10^6 Btu) represents a required NO_x reduction of 46 percent. Therefore, maximum reduction efficiencies must be obtained from these control techniques if they are to achieve the stringent control level when operating singly. It is difficult to predict whether low NO_x burners like the Kawasaki, EER, or TRW units can achieve 50 percent reduction for all watertube boilers. With little information available on these and other developing burners, such assurance does not exist at the present time. However, LNBs were still chosen as the best stringent control system based on their potential for cost-effective control with little expected adverse impacts.

For staged combustion to achieve 46 percent NO_x reduction, it would mean burner operation with 70 to 90 percent stoichiometry. However, prolonged tests with areas of the boilers in severe reducing atmospheres caused by 70 percent burner stoichiometries have not been conducted. But based on utility boiler experience, burner stoichiometries less than 90 percent may not be acceptable because of increased corrosion and tube wastage. Therefore, staged combustion as a single technique control system would probably not be feasible considering operational problems.

The only other alternative to low NO_x burners for stringent control would be ammonia injection. Although the technique has seen limited commercial operation in Japan, this control system represents a several fold more costly alternative for NO_x reduction than the other two previously described systems. In addition, ammonia emissions will inevitably create some operational problems for high sulfur oil-fired boilers. These problems would lead to increased boiler maintenance, increasing operating cost over and above expected control costs. Furthermore potential emissions of NH_3 and byproducts cause environmental concern.

3.3.3 Effects of Fuel Nitrogen

It should be noted that the above discussed controlled emission levels for residual oil firing may be difficult to achieve for boilers firing high nitrogen content fuel (e.g., >0.3 weight percent nitrogen). Indeed, Figure 3-1 indicates a possible trend of increasing total NO_x emissions with fuel nitrogen content, unlike the behavior exhibited by coal-fired boilers. A possible explanation may be the following: (1) the fractional conversion of fuel nitrogen to fuel NO_x increases with decreasing fuel nitrogen content, and (2) residual oil generally has much lower fuel nitrogen content than does coal (Reference 3-4). For high nitrogen content residual oil, a possible moderate controlled (low excess air operation) NO_x level is 200 ng/J (0.47 lb/10^6 Btu). Note in Figure 3-1 that combustion air preheat appears to have no effect on NO_x emissions from residual oil-fired boilers, as expected.

3.4 CANDIDATE BEST CONTROL SYSTEMS FOR DISTILLATE OIL-FIRED INDUSTRIAL BOILERS

NO_x emissions from distillate oil combustion are primarily from thermal NO_x formation. Distillate oils generally contain less than 0.05 percent of fuel bound nitrogen. The emissions data used here are primarily from an EPA sponsored study in which fuel nitrogen content of the oil varied from 0.013 to 0.045 percent (Reference 3-4).

Combustion modifications which are primarily effective in reducing thermal NO_x formation are:

- Flue gas recirculation (FGR)
- Reduced air preheat (RAP)
- Load reduction with reduced oxygen
- Low NO_x burners
- Staged combustion

The relatively low uncontrolled baseline NO_x emissions of distillate oil-fired industrial boilers are reflected in the suggested NO_x control levels of 86, 65, and 43 ng/J for moderate, intermediate, and stringent control, respectively.

As will be observed in the following subsections, these control levels can in most cases be met with commercially available techniques. Table 3-10 lists the best candidates for NO_x emission control for each of the three control levels. However, it is interesting to note that watertube boilers with preheated combustion air tend to have significantly higher NO_x emissions than those without preheated air. Furthermore, this behavior was irrespective of unit capacity (Reference 3-3).

Firetube boilers usually have lower combustion intensities than watertube units; consequently, the formation of thermal NO_x would be expected to be lower (Reference 3-3). However, this was not the case for the boilers tested, though the differences measured were not large.

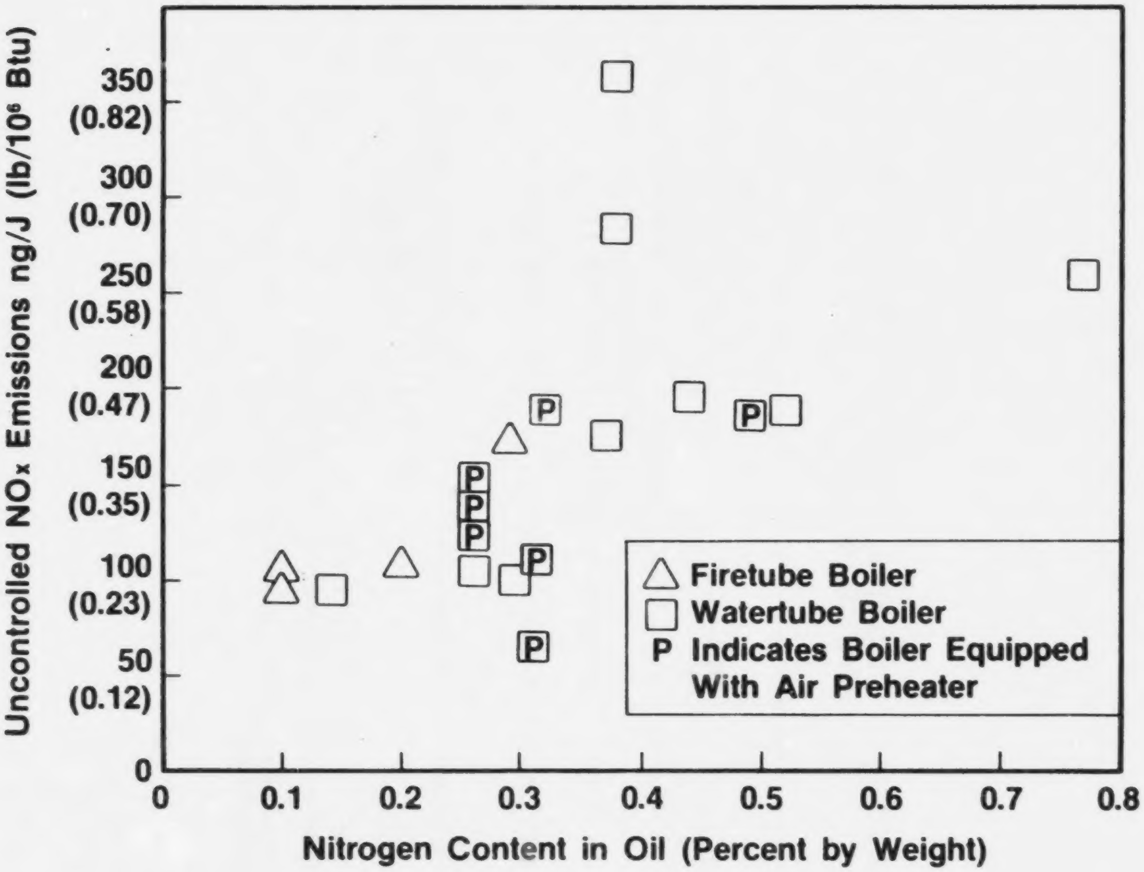

Figure 3-1. Effect of fuel nitrogen content on NO_x emissions from residual oil-fired industrial boilers.

TABLE 3-10. BEST CONTROL SYSTEMS FOR DISTILLATE OIL-FIRED INDUSTRIAL BOILERS[a]

Boiler Equipment Type	Baseline NO_x Emissions ng/J (lb/10^6 Btu)	Level of Control		
		Moderate 86 ng/J (0.2 lb/10^6 Btu)	Intermediate 65 ng/J (0.15 lb/10^6 Btu)	Stringent 43 ng/J (0.1 lb/10^6 Btu)
Firetube	75 (0.175)	No control necessary	Low excess air	1. Flue gas recirculation 2. Low NO_x burners**
Watertube not equipped with air preheater	55 (0.128)	No control necessary	No control necessary	1. Flue gas recirculation 2. Low NO_x burners** 3. Staged combustion air*
Watertube equipped with air preheater	90 (0.209)	Low excess air	1. Reduced air preheat 2. Flue gas recirculation 3. Low NO_x burners** 4. Staged combustion*	1. Reduced air preheat + flue gas recirculation 2. Reduced air preheat + Low NO_x burners**

T-1761

[a] Low excess air operation is recommended practice whenever controls are required

*Commercially offered but not demonstrated for this boiler/fuel category.
**Commercially offered but not demonstrated.

The following subsections discuss the criteria for relating the candidates for best NO_x control systems and the priority in which they have been listed in Table 3-10.

3.4.1 Firetube Boilers

Emissions from six firetube boilers burning distillate oil averaged approximately 75 ng/J (Reference 3-3). However, only two of these boilers were tested with combustion modifications. In addition, the combustion modifications used were limited to low excess air and load reduction. The effectiveness of other combustion modification control systems selected for firetube boilers is based on results obtained on watertube boilers. The effectiveness of the controls does not vary significantly between these two equipment types.

With such a low average baseline NO_x level (75 ng/J), firetube boilers should not need any controls to meet the moderate control level (86 ng/J) for distillate oil firing.

3.4.1.1 Intermediate Control Level

Low excess air combustion on two firetube boilers reduced NO_x emissions 18 percent on the average (Reference 3-3). Excess oxygen was reduced in both cases from the baseline level of approximately 5.7 percent to 3.2 percent. Operation of the boiler burning distillate oil with a 3 percent excess oxygen level allows complete fuel-air mixing which in turn keeps combustible emissions at a minimum. This expected 18 percent NO_x reduction should be sufficient for the firetube boilers to meet the 65 ng/J intermediate control emission level. Operation of distillate oil burners below 3 percent excess oxygen is often feasible especially with today's designed LEA burners (Reference 3-21). The increased boiler efficiency and subsequent fuel saving due to LEA operation would also compensate for the cost of the system. Expenditures caused by LEA operation include the installation and operation of control equipment, including CO and O_2 monitors.

Thus, LEA is the best candidate control for NO_x reduction for firetube boilers required to meet the intermediate NO_x emission control level of 65 ng/J. Other, more elaborate and costly techniques are not necessary.

3.4.1.2 Stringent Control Level

The 40 percent NO_x reduction from baseline emissions required by the stringent control level eliminates the use of LEA, although LEA is still desirable because of increased boiler efficiency. The best control system for this NO_x reduction performance is flue gas recirculation. Flue gas recirculation is a very effective control system with reported NO_x reductions of up to 73 percent for watertube boilers (References 3-3 and 3-4, and 3-9). Potential operational problems such as flame instability should be eliminated with proper engineering and testing. Environmental impacts such as possible increased organic emissions are expected to be minimal, although further investigation is definitely desirable.

Flue gas recirculation was selected over low NO_x burners primarily because of the commercial availability of FGR. However, LNB designs capable of 40 percent NO_x reduction, once commercially available and demonstrated, will be much more cost effective. Reductions in NO_x emissions for low NO_x burners have been reported in the 20 to 50 percent range.

Additional NO_x control candidates would be ammonia injection and staged combustion. Although both of these techniques are feasible, they may prove to be inapplicable to firetube boilers because of equipment limitations. In addition, the cost of ammonia injection might prove to be more than the cost of the boiler itself.

In summary, flue gas recirculation is the preferred stringent control technique with low NO_x burners as the second option for distillate oil-fired firetube boilers.

3.4.2 Watertube Boilers Without Air Preheaters

Watertube boilers firing distillate oil and not equipped with air preheaters are usually smaller than 15 MW (50 x 10^6 Btu) heat input, although a 58 MW unit has been tested (References 3-3 and 3-4). NO_x emissions from these equipment types averaged approximately 55 ng/J (References 3-3 and 3-4). This baseline emission level is lower than both the moderate and intermediate control levels of 86 and 65 ng/J, respectively, so no controls are needed. However, to meet stringent levels some form of NO_x control will be needed.

NO_x reduction to 43 ng/J can be met by reducing the baseline level of 55 ng/J by 22 percent. This reduction should be easily achievable with flue gas recirculation (up to 70 percent NO_x reduction) or low NO_x burners (20 to 50 percent). Low excess air combustion reduced NO_x emissions from watertube boilers only about 4 to 12 percent when excess oxygen was lowered from approximately 5.5 to 3.5 percent. Although burner operation with excess oxygen lower than 3.5 percent is possible (Reference 3-21) it is unclear whether higher NO_x reductions could be achieved.

Flue gas recirculation was selected as the best candidate for stringent control based on its commercial availability and recorded performance. Recirculation rates of less than 30 percent are deemed sufficient to achieve this control level. At this rate, no major operational impacts are expected if the burner is modified to allow for the increased excess flowrate.

Low NO_x burners will probably be more cost effective once they are commercially available and demonstrated. They may become the candidate best system of control for reducing NO_x emissions to 43 ng/J. Low NO_x burners are especially attractive for single burner units such as packaged watertubes because the incremental cost for one LNB is considered minimal. However, the prototype low NO_x burners under current development may be of too large capacity for the smaller package units.

Staged combustion is another alternative control system. Staged combustion may prove to be more attractive than LNB for multiburner units. However, watertube boilers not equipped with air preheaters are generally of the package type with only one burner. For these units, air injection by means of ports down stream from the burner can be used to achieve staged combustion (see Section 2). Control of NO_x with this type of staged combustion is considered still at the experimental stage and more costly than control with LNB.

In summary, flue gas recirculation is considered the preferred method for stringent control of distillate oil-fired watertubes not equipped with air preheaters.

3.4.3 Watertube Boilers Equipped with Preheaters

Watertube boilers with preheated combustion air are generally larger than 15 MW (50 x 10^6 Btu/hr) heat input (Reference 3-3). Baseline NO_x emissions from a limited number of these units averaged about 90 ng/J (Reference 3-4). Currently available combustion modification control systems are capable of achieving the moderate, intermediate, and stringent control levels for distillate oil firing.

3.4.3.1 Moderate Control Level

Low excess air firing should be more than adequate to reduce the baseline NO_x emissions of 90 ng/J to the moderate control level of 86 ng/J with increased boiler efficiency and minimal adverse impacts.

3.4.3.2 Intermediate Control

Combustion air temperature were not be reduced during the test program on the watertube boilers equipped with air preheaters. Therefore the effect of reduced air preheat (RAP) on these units cannot be clearly defined. However, based on results with natural gas, another clean fuel, it is speculated that RAP can reduce NO_x emissions by the 30 percent required by the intermediate control level of 65 ng/J. The loss in efficiency caused by the increased flue gas temperature can be averted for new units by installing an economizer instead of an air preheater. Economizers offer some operational advantages over air preheaters as well as reduced NO_x emissions (Reference 3-21). The primary advantage is the lower capital cost, sometimes nearly one-half of that of an air preheater (Reference 3-25).

Therefore, RAP or ambient temperature combustion air for new watertube boilers designed to fire distillate oil was selected as the best system for intermediate control. Alternative controls include flue gas recirculation, low NO_x burners, and staged combustion.

Flue gas recirculation is a very effective and available technique, but is also very costly, therefore it should be considered as an alternative to RAP only if replacing the air preheater with an economizer in a new unit is not feasible.

The remaining alternatives are low NO_x burners and staged combustion. For single burner packaged units, LNB is probably considered more desirable. However, LNB performance and operation have not been thoroughly demonstrated. Similarly, overfire air injection for multiburner units is a very attractive control system, probably more so than LNB. Staged combustion can reduce NO_x from watertube boilers firing distillate oil by 30 to 40 percent on the average (References 3-4 and 3-9).

In general, watertube boilers with ambient combustion air temperature are capable of meeting the intermediate emission level of 65 ng/J with minimal adverse impacts. Therefore it is recommended that new units be designed with an economizer instead of an air preheater. Alternative control candidates include FGR or LNB for packaged single burner boilers and OFA for multiburner units. Staged combustion for packaged watertube boilers is also a candidate, although, this control system is still at the experimental stage.

3.4.3.3 Stringent Control Level

The stringent control level of 43 ng/J can be obtained by combining reduced air preheat (RAP) with another combustion modification such as FGR or LNB. The RAP plus FGR control system was selected as the best candidate again based on availability, even though its cost is generally expected to be higher than for RAP plus LNB control systems.

Alternative control systems include the use of ammonia injection combined with one other combustion modification. Reduced air preheat is preferred because it is expected to have the least operational and cost impact considering the flue gas heat recovery with an economizer. For boilers which must be equipped with air preheaters, FGR or LNB may still be adequate. Otherwise, costly NH_3 injection may also be required.

3.5 CANDIDATE BEST CONTROL SYSTEMS FOR NATURAL GAS-FIRED INDUSTRIAL BOILERS

Formation of NO_x from the combustion of natural gas is entirely from thermal fixation of nitrogen in the combustion air. Combustion parameters primarily affecting thermal NO_x formation are peak flame temperature, oxygen concentration and exposure time at peak flame temperatures. The following are applicable combustion modification controls which effectively reduce thermal NO_x:

- Flue gas recirculation
- Reduced air preheat
- Staged combustion and low excess air
- Load reduction with reduced oxygen
- Low NO_x burners

Table 3-11 lists the candidate best systems of combustion modification for natural gas-fired industrial boilers. Natural gas-fired boilers have been categorized into three main types: firetubes, watertubes not equipped with air preheaters, and watertubes equipped with air preheaters. This characterization was made because the baseline NO_x emissions of each of these types were significantly different, as well as because of alternate available control strategies.

Firetube boilers are the lowest emitters with approximately 40 ng/J emission level. These boilers are usually not equipped with air preheaters because of their small size, making heat recovery too costly to implement. Watertube boilers without preheated combustion air exhibited average NO_x emissions of 45 ng/J, while those units with air preheaters emitted significantly higher NO_x, 110 ng/J.

The following discussion summarizes the reasons for the selection and the order of the combustion modification systems for each of these major natural gas-fired industrial boilers, as shown in Table 3-11.

3.5.1 Firetube Boilers

The low baseline NO_x emissions (40 ng/J) from firetube boilers require no controls for meeting the moderate, intermediate, or stringent levels for gas-fired boilers.

It is not considered cost-effective to require further control beyond the stringent level of 43 ng/J because of the firetube boiler's small size with very low baseline NO_x emissions level.

3.5.2 Watertube Boilers Without an Air Preheater

Watertube boilers not equipped with air preheaters usually have heat input capacities lower than 15 MW (50 x 10^6 Btu/hr), although some larger units do exist (Reference 3-4). However, increasing concern about energy saving and fuel economy has resulted in numerous industrial boiler

TABLE 3-11. BEST CONTROL SYSTEMS FOR NATURAL GAS-FIRED INDUSTRIAL BOILERS[a]

Boiler Equipment Type	Baseline NO_x Emissions ng/J (lb/10^6 Btu)	Level of Control		
		Moderate 86 ng/J (0.2 lb/10^6 Btu)	Intermediate 65 ng/J (0.15 lb/10^6 Btu)	Stringent 43 ng/J (0.1 lb/10^6 Btu)
Firetube	40 (0.093)	No control necessary	No control necessary	No control necessary
Watertube not equipped with air heater	45 (0.105)	No control necessary	No control necessary	Low excess air
Watertube equipped with air heater	110 (0.256)	1. RAP[b] 2. FGR 3. SCA* 4. LNB**	1. RAP + FGR[b] 2. RAP + LNB** 3. RAP + SCA*	1. RAP + FGR[b] 2. RAP + LNB** 3. RAP + NH_3** injection

T-1762

[a] Low excess air operation is recommended practice whenever controls are required.

[b] RAP = Reduced Air Preheat
FGR = Flue Gas Recirculation
SCA = Staged Combustion Air
LNB = Low NO_x Burners

*Commercially offered but not demonstrated for this boiler/fuel category.
**Commercially offered but not demonstrated.

manufacturers offering flue gas heat recovery devices such as air preheaters or economizers (Reference 3-21). This section addresses only those boilers not equipped with air preheaters.

Baseline NO_x emissions from these boiler types were found to be very low (45 ng/J), requiring no combustion modification to meet the moderate or intermediate NO_x control levels of 86 and 65 ng/J, respectively. With such a low baseline NO_x level, low excess air firing should certainly be adequate for meeting the stringent control level of 43 ng/J.

3.5.3 Watertube Boilers with Air Preheaters

Baseline NO_x emissions from gas-fired watertube boilers equipped with combustion air preheaters are significantly higher than similar boilers using ambient temperature combustion air (110 versus 45 ng/J). Section 2 has shown that if the air preheater is bypassed, NO_x reductions of up to 55 percent can be obtained, thus reducing the emission level from approximately 110 to 50 ng/J, nearly the level of units without air preheaters.

Therefore, substantial control levels can be achieved by bypassing air preheaters on existing units and building new boilers without air preheaters. However, in both cases the flue gas heat loss must be recovered by some other means; otherwise the control becomes very unattractive due to large boiler efficiency losses (one percent for every 20K or 42°F increase in stack temperature). One alternate flue gas heat recovery device is the economizer. As is the case for distillate oil-fired boilers, the economizer offers smaller capital investment and lower fan power requirements than an air preheater.

The following subsections describe the criteria used in selecting the order of control systems shown in Table 3-11 for gas-fired boilers with combustion air preheaters.

3.5.3.1 Moderate Control Level

As discussed above, replacement of air preheaters with economizers helps to reduce NO_x levels, and is also cost effective. Therefore, for new gas-fired watertube boilers the best system of control to achieve an emission level of 86 ng/J (or lower) is to install economizers in place of air preheaters. Retrofit changes are not considered viable due to boiler design differences as well as high costs.

If an air preheater is installed, three other options can be considered. These are flue gas recirculation, staged combustion, and low NO_x burners. Flue gas recirculation is a very effective and available technique, but also very costly, and should be considered as an alternative to RAP only if replacing the air preheater with an economizer in a new unit is not feasible. Staged combustion together with low excess air was selected as another option because it is a demonstrated technology and is commercially available for utility size units. However, the choice between LNB or staged combustion highly depends on the boiler configuration. Single burner units might be more amenable to LNB than staged combustion because of the lower expected cost (see Section 4). However, staged combustion technology is presently available while LNB technology for natural gas combustion still needs demonstration in the U.S. (References 3-26, 3-27).

In summary, reduced air preheat through replacement of the air preheater with an economizer is the preferred, cost-effective method for moderate control of gas-fired watertube boilers. For a new unit, there should be no adverse process, cost, or environmental impact.

3.5.3.2 Intermediate Control Level

When combined with no air preheat, flue gas recirculation, low NO_x burners, and staged combustion are candidate control systems to achieve the intermediate control level of 65 ng/J. Flue gas recirculation (FGR) was again selected as the best candidate control as for distillate oil-firing because of its significant effectiveness and its commercial availability. For single burner units, however, low NO_x burners may prove to be much more cost effective and would be selected as the best control even though demonstrated gas-fired low NO_x burners are not yet commercially available. For multiburner units, staged combustion combined with LEA might be preferred over low NO_x burners primarily because of its known effectiveness (25 to 45 percent NO_x reduction) and its nearer-term availability.

3.5.3.3 Stringent Control Level

NO_x emissions from gas-fired industrial boilers can be reduced to 43 ng/J only if the combustion air is not preheated. In most cases the combination of no air preheat and flue gas recirculation can reduce the NO_x emissions to this level because of the high effectiveness of flue gas recirculation with natural gas fuel (up to 75 percent). This control system of RAP and flue gas recirculation is the preferred one because of its current availability and effectiveness.

Low NO_x burners are not yet demonstrated. In addition, their performance (up to 50 percent NO_x reduction) would not be sufficient to lower NO_x emissions to 43 ng/J. However, when low NO_x burners are combined with reduced air preheat, the stringent control level may be achievable. There are no reported tests to verify this.

A third alternative is ammonia injection combined with reduced air preheat. But this system is not thoroughly demonstrated and furthermore is significantly more costly than the flue gas recirculation/reduced air preheat system. In addition, there are environmental concerns with possible ammonia and byproduct emissions. Furthermore implementation and operational problems need to be resolved.

3.6 SUMMARY

Alternative emission control systems which achieve moderate, intermediate, and stringent levels of NO_x control have been selected. These control levels were based on uncontrolled baseline emission levels and the capabilities of combustion modification controls. Tables 3-7 through 3-11 summarize the candidates for best control systems and emission levels achievable for each of the major industrial boiler/fuel categories. Tables 3-2 through 3-5 highlight the main performance characteristics of candidate control systems. Selection criteria for these candidate best control systems were based on the effectiveness, commercial availability or R&D status, operational impact, and reliability of each system. Energy, environmental, and cost impacts were also considered.

Results to date indicate that low excess air (LEA) or overfire air (OFA) form the best system for moderate (301 ng/J) and intermediate (258 ng/J) NO_x control for pulverized coal-fired industrial boilers. However, those boilers with high baseline NO_x emissions may need to use a combination of OFA and LEA to achieve the intermediate control level. Staged combustion combined with low excess air can achieve the stringent control level of 215 ng/J. Alternative controls include low NO_x burners (LNB) and ammonia injection; both techniques are under development.

Spreader stokers are the only major stoker boiler types with average uncontrolled NO_x emissions above 258 ng/J. Low excess air and overfire air constitute the best candidate control system capable of reductions to 215 ng/J. Any NO_x reduction beyond this level can only be achieved with NH_3 injection (an unproven technique), possibly down to 129 ng/J. The other major stoker types, chain grate and underfeed, have average uncontrolled NO_x emissions below 172 ng/J. Control of these units to 129 ng/J is possible with LEA.

The candidate best control systems for residual oil-fired industrial boilers are low excess air, low NO_x burners, and staged combustion. The low NO_x burners under development are projected to reduce NO_x emissions to the stringent level (86 ng/J). An alternative control is NH_3 injection (an unproven technique). Candidate best control systems for distillate oil- or gas-fired boilers are reduced air preheat, flue gas recirculation, and low NO_x burners, in that order, lowering NO_x to 65 ng/J. Reduced air preheat combined with flue gas recirculation or with low NO_x burners may potentially reduce NO_x emissions to 43 ng/J.

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SECTION 4

COST IMPACT

The cost impact of combustion modification techniques for controlling NO_x emissions from industrial boilers is discussed in this section. The controls considered are those discussed in Section 3 as candidates for best NO_x emissions control system. Selection criteria for the best control system were based on the effectiveness, commercial availability or R&D status, operational impact, and reliability of each system. Estimates of the energy, environmental, and cost impacts were also considered. This section examines the cost impacts in greater detail.

4.1 COST ANALYSIS

In the evaluation of NO_x controls for industrial boilers, the cost of boiler systems with controls are compared to the costs of uncontrolled and State Implementation Plan (SIP) controlled systems. (SIP control levels are summarized in Table 5-1.) Section 4.1.1 reviews the components that go into control costs, while Section 4.1.2 reviews the cost basis and assumptions.

4.1.1 Components of Control Costs

Nitrogen oxides control techniques can have two major cost components. First, the control methods will usually require additional hardware, increasing the cost of the boiler to the user. Second, the cost of producing steam will probably be increased due both to the increased capital charge to be annualized (referred to as annualized capital cost) and any changes in operating, maintenance, and energy costs (referred to collectively as annualized operating costs). The price of steam will not always rise with addition of controls; for example, as will be shown later, low excess air operation can decrease the cost of steam in some cases.

The capital and operating costs of NO_x controls discussed here are engineering estimates based on limited published costs and discussions with equipment vendors. The largest component of operating costs are often due to increased energy consumption. These changes in energy consumption are discussed in Section 5 and those values are used in estimating the changes in steam cost due to NO_x controls.

Indeed, it has been found for NO_x controls for utility boilers that losses in boiler efficiency (increased fuel consumption) can add up to over half the cost-to-control (Reference 4-1). For example, a 0.25 percent loss in boiler efficiency with staged combustion can translate to one third of the control cost. Unfortunately, these changes in boiler efficiency with NO_x controls have not been precisely established for utility or industrial boilers. Therefore, although equipment and operating costs are discussed here in as great detail as available data permit, the large unknown in energy costs should be noted when discussing control costs. In other works, a very small variation in boiler efficiency loss can lead to a very large fluctuation in control costs. In many cases, then, a detailed discussion of equipment cost estimates, etc. can become moot.

Since NO_x control techniques are not widely used on industrial boilers, very little is known about long term operation. Thus one area of concern is how NO_x controls affect day-to-day operation. Industrial boilers are operated with a minimal amount of operator attention and run under changing loads. Therefore the combustion modifications that are made for NO_x control may also require that the boiler control system (e.g., air and fuel flow controls) be modified. The cost of an additional boiler control system has been estimated and included in the presented prices, but without long term tests, a true modification cost can not be given. Also, since the actual costs depend on site and use of boiler, only estimated prices for a typical boiler can be given.

The costs of the following control techniques are discussed in this section: low excess air (LEA), staged combustion air (SCA) -- usually overfire air (OFA) or sidefire air (SFA), flue gas recirculation (FGR), low NO_x burners (LNB), reduced air preheat (RAP), and ammonia injection. The following paragraphs describe the required and/or recommended equipment needed when implementing these combustion modification techniques. The costs for the required and/or recommended equipment are included in the prices that will be listed.

Low excess air operation may require an oxygen trim system consisting of a flue gas O_2 analyzer along with the control equipment for regulating air flow. This is in addition to the normal air flow control system. Wind box modifications may also be required for multi-burner boilers.

Staged combustion requires air ports and possible windbox modification. Several air ports may be required to allow firing of different types of fuels. Larger forced draft fan power also may be needed, and an oxygen trim system should probably be installed.

Flue gas recirculation requires a larger forced draft fan and the associated duct work to recycle a portion of the flue gas. Windbox and burners may need to be modified to accommodate the additional gas flow. A control system to regulate the combustion oxygen and the amount of the flue gas recirculated would probably also be needed.

Low NO_x burner operation may require a larger forced draft fan if the burners have an increased pressure drop. Windbox modifications may also be required. An oxygen trim system is recommended to allow operation at the lowest possible excess air.

Ammonia injection requires injector ports, the injection system, and the ammonia handling and storage system. Ammonia injection may also require several different injection port locations and a control device to switch ports as load changes. An air compressor to supply a carrier gas for the ammonia would also be needed. Controls to regulate the flow of NH_3 will also be required. Since the process is patented by Exxon, they will require a licensing fee. This fee was not included in the present analysis as that cost is a negotiable item and the information is not available.

4.1.2 Cost Basis

Table 4-1 summarizes the simplified cost basis used in evaluating NO_x controls. Capital costs represent the initial investment for the control: equipment and installation costs. On an annualized basis, the initial investment can be levelized into capital recovery charges and combined with taxes and insurance to comprise annualized capital charges. Annualized capital charges plus annual operating costs give the total cost to control per year.

TABLE 4-1. COST BASIS FOR EVALUATING NO_x CONTROLS

- Capital Costs (Initial Investment)
  - Equipment Costs
  - Installation Costs, Indirect
    - Engineering
    - Construction and Field Expense
    - Construction Fees
    - Start-up
    - Performance Test
  - Installation Costs, Direct
  - Contingencies
- Annualized Costs
  - Capital Charges (Fixed Costs)
    - Capital Recovery
    - Taxes
    - Insurance
  - Operating Costs
    - Utilities
    - Raw Materials
    - Operating Labor
    - Maintenance
    - Fuel Costs

Since experience with industrial boiler NO_x controls is very limited, a detailed breakdown of the costs into the various capital and operational cost components as illustrated in Table 4-1 was not always possible. The analysis relied heavily on estimates from equipment vendors and published data from utility boiler experience. Where information was lacking, engineering estimation rules as outlined in Reference 4-2 were used. Costs were collected from various sources and extrapolated to the boiler size under consideration. Using engineering judgement, a typical cost was estimated from these extrapolated values.

Following the guidelines of the EPA memo which described the suggested cost analysis approach used here (Reference 4-21), the reliability of the cost estimates presented here is estimated to be no better than plus or minus 30 percent except for ammonia injection and low NO_x burners. Since these last two techniques represent untried technologies, the reliability of their costs is estimated to be plus 100 percent.

As discussed in Section 2, the limited control performance data does not allow one to determine the effect of different coal types upon NO_x emissions. Hence the control cost estimates presented here are not broken down by coal type.

In calculating the costs of control systems, several assumptions were made. The annualized capital charges, were taken to be 20 percent of the total installed cost of the combustion modification, and the annualized operating labor and maintenance costs were taken to be 5 percent of the total installed cost. Twenty percent was the factor used for annualized capital charges because it is common industrial practice to use 20 percent when presenting a first estimate of annualized capital charges. For example, see the EPA Standard Support and Environmental Impact Statement for Stationary Gas Turbines (Reference 4-3), the cost estimates for ammonia injection (References 4-4 and 4-5), and the utility industry price estimates for NO_x control given in Reference 4-6. This 20 percent includes four percent for G&A, taxes, and insurance and a capital recovery factor of 16 percent. The utility industry also used 5 percent annualized operating labor and maintenance cost for NO_x combustion modification techniques for utility boilers (Reference 4-6). Since there is no long term operating experience with combustion modifications for industrial boilers, it was decided to use five percent as a first estimate.

An industrial boiler is assumed to be 82 percent efficient without an air preheater or economizer and 84 percent efficient with one except for a pulverized coal-fired boiler which is assumed to be 87 percent efficient (References 4-7 and 4-8). To generate one kilogram of steam requires 0.00256 GJ (1100 Btu/lb) of heat. The load factors and fuel costs given by PEDCo (Reference 4-2) were used in the cost analysis used. PEDCo used load factors of 45 percent for boilers smaller than 7 x 10^3 kg steam/hour (15 x 10^3 lb steam/hr) and 60 percent for the larger sizes. The fuel prices used are \$2.84/GJ for No. 2 oil, \$2.21/GJ for No. 6 oil,

$1.85/GJ for natural gas, and $1.10/GJ for low sulfur coal. The price of No. 6 oil is increased by 20 percent to $2.65/GJ to account for the cost of heating the fuel when firing and keeping the storage tank warm. The fuel prices, as well as all other costs to be presented, are 1978 prices.

In the following discussion, costs to modify the boiler are given as a percentage of the boiler's installed cost, while the steam costs include the entire steam plant. The total steam plant costs more than that of the boiler alone because it includes additional equipment such as the smoke stack and water treatment system. The boiler and steam production costs used are from a report by PEDCo presented to the EPA-OAQPS (Reference 4-2). Except for adding an O_2 trim system and ammonia injection, retrofit costs were assumed to be twice that of installing NO_x controls on a new unit as was found by one author for a small industrial boiler (Reference 4-9). However, this may be optimistic and retrofit control costs may actually be four times that for new designs. The factor of two assumed here is just for the purposes of a first estimate in control costs. It should be reiterated that the control costs presented in this section, as well as achievable NO_x control levels, are based on very limited data.

The cost estimates presented are only for reaching the moderate, intermediate, and stringent control levels discussed in Section 3. It is usually possible to achieve lower NO_x levels by extending the degree of application of the control technique but the control costs were estimated assuming that the indicated technique is used just to reach the indicated level of control. In many cases, using even lower excess air can increase efficiency, lower the required energy, and reduce the steam cost.

The cost data will be presented in tables in which the capital and annualized incremental costs and cost effectiveness of NO_x controls will be summarized (the limited available details are given in the Appendix). The costs are incremented from the costs of the basic uncontrolled systems. In the tables, the annualized incremental costs were calculated by the following formulas (units of mills/10^3 kg steam).

Total Annual Cost = Annualized Fixed Costs Plus Operating Cost

Annualized Fixed Costs =

$$\frac{\text{(Total Installed Cost of Control)(0.2)(1000)}}{\text{(Hours/yr) (Load Factor) (Boiler Capacity, } 10^3 \text{ kg steam/hr)}}$$

Operating Cost = Fuel + Raw Materials + Utilites + Operating Labor + Maintenance

$$\text{where Fuel Cost} = \frac{\text{(Thermal Efficiency Change)(GJ/}10^3\text{kg steam)(mills/GJ)}}{\text{(Boiler efficiency)}}$$

$$\text{Utilities Costs} = \frac{\text{(Fan Efficiency Loss)(Boiler Heat Input)(26 mills/kwh)}}{\text{(0.65) (Boiler Capacity, }10^3\text{ kg steam/hr)}}$$

and Operating Labor and Maintenance Cost =

$$\frac{\text{(Total Installed Cost of Control)(0.05)(1000)}}{\text{(Hours/yr)(Load Factor)(Boiler Capacity, }10^3\text{ kg steam/hr)}}$$

Overhead charges have already been incorporated into the labor and maintenance costs. Thermal efficiency and fan power changes are discussed in Section 5. The cost effectiveness of a NO_x control technique is calculated by the following formula:

$$\text{Cost effectiveness} = \frac{\text{(Total Annualized Cost)(Boiler Capacity, }10^3\text{ kg steam/hr)}}{\text{(Heat Input)(Emission Change)}}$$

where Emission Change = Baseline NO_x Level - NO_x Control Level

Thus cost effectiveness has units of \$/kg NO_x reduced. The baseline and controlled NO_x levels, have been discussed in Section 3. Figures 4-1, 4-2, and 4-3, summarize estimated annualized control costs versus NO_x emission levels for coal and residual oil-fired boilers and for firetube boilers firing natural gas or distillate oil. The following sections will elaborate on these figures.

4.2 CONTROL COSTS FOR COAL-FIRED BOILERS

The costs for pulverized coal units are engineering estimates based on published data, manufacturer quotes, and utility boiler experience (References 4-1 and 4-10 through 4-14).

Stoker unit costs are engineering estimates based on published data and manufacturer's estimates (References 4-10 through 4-15). Tables 4-2, 4-3, 4-4, and 4-5 list the cost estimates for new and retrofitted units. And Figure 4-1 shows a graph of estimated annualized cost versus NO_x level. Recall that the moderate, intermediate, stringent, and SIP control levels were defined in Section 3.

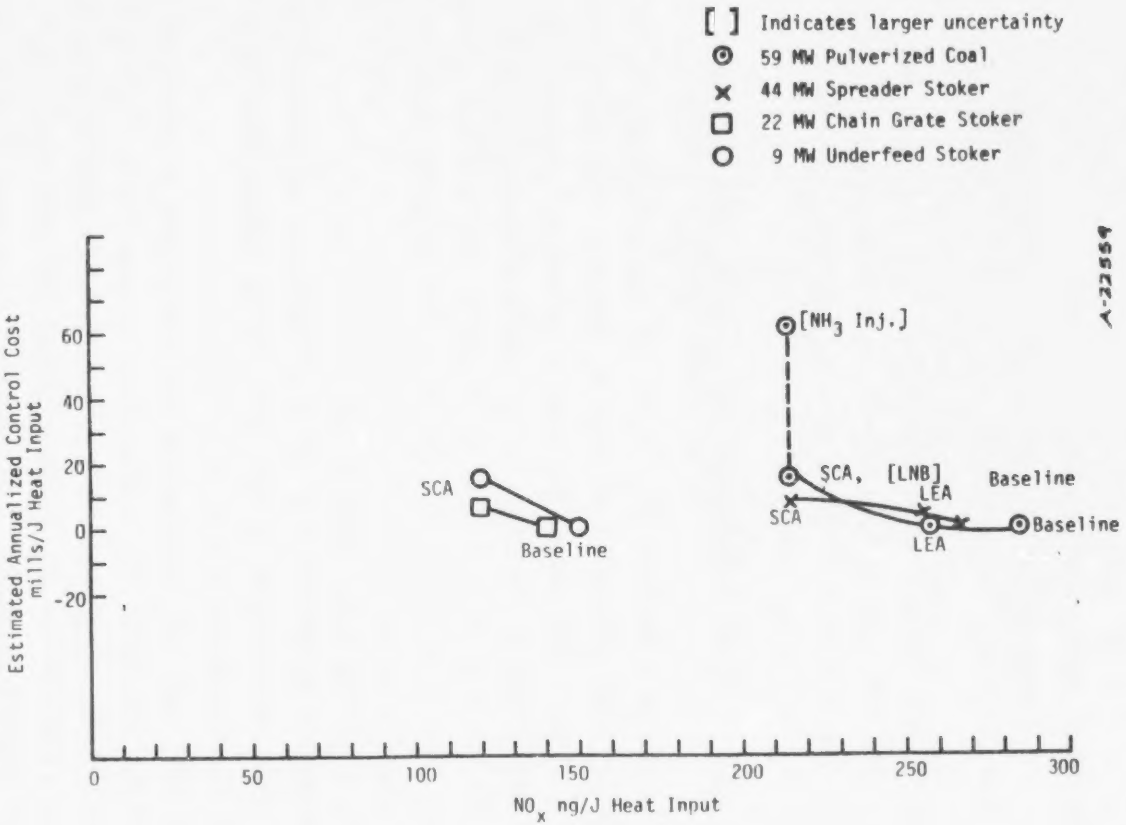

Figure 4-1. Estimated annualized control cost versus NO$_x$ level for coal-fired boilers (costs are only first estimates).

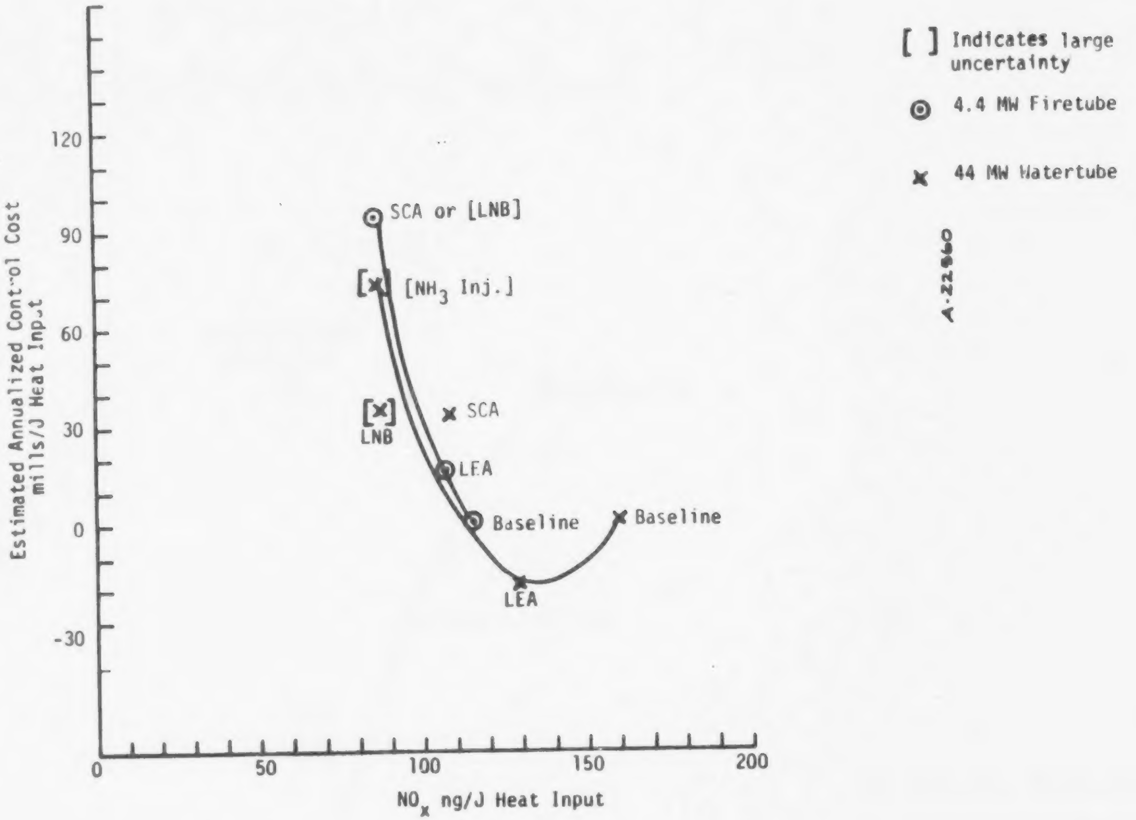

Figure 4-2. Estimated annualized control cost versus NO_x emission level for residual oil-fired boilers (costs are only first estimates).

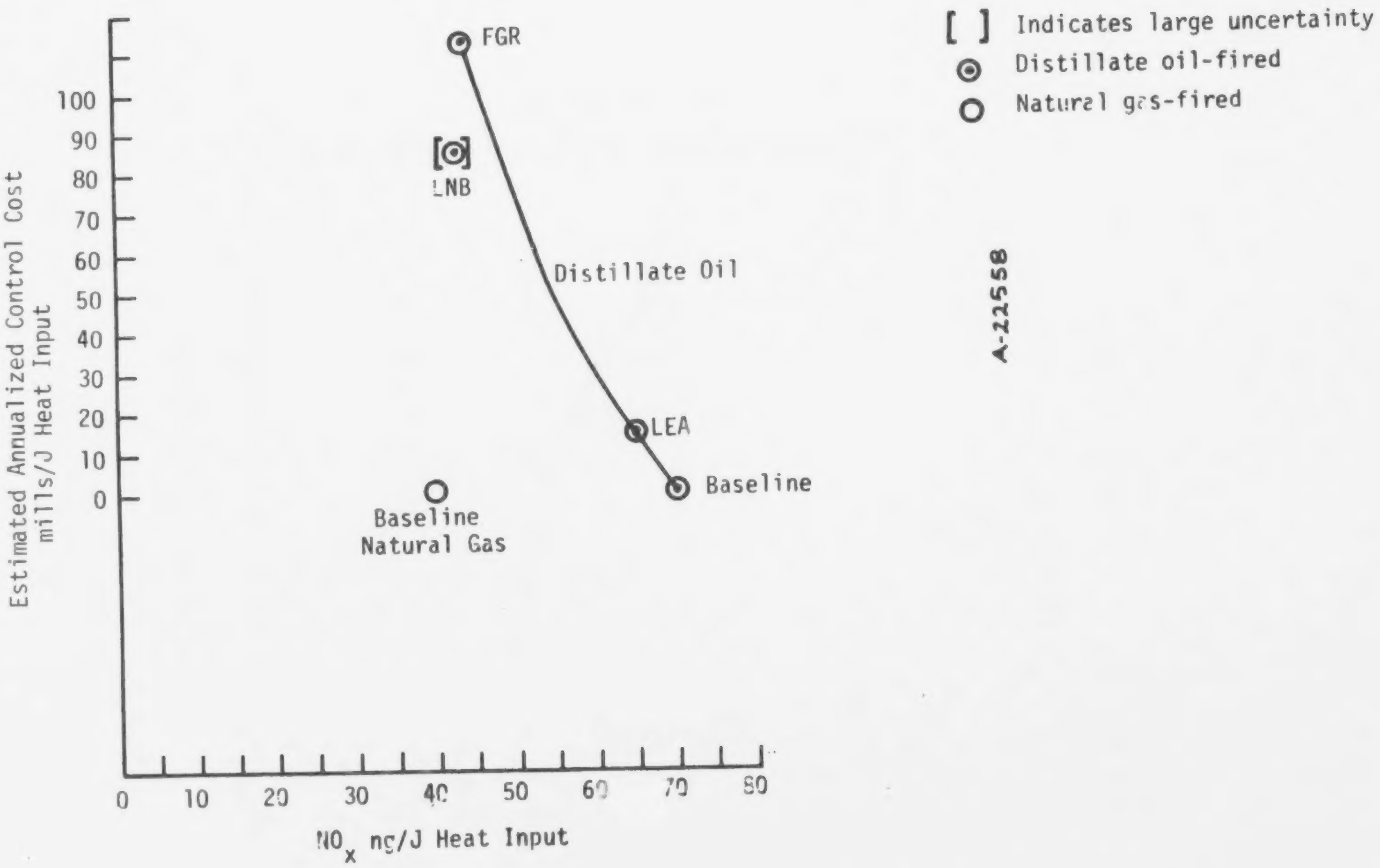

Figure 4-3. Estimated annualized control cost versus NO$_x$ emission levels for distillate oil and natural gas fired 4.4 MW firetube boiler (costs are first estimates only).

TABLE 4-2. ESTIMATED COSTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR NEW COAL-FIRED BOILERS

System				Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 $	Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)				Fixed Costs	Operating Costs	Total Costs	
					$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{\text{GJ input}}$
Pulverized Coal	59 (200)	No Controls SIP Moderate	--	--	--	--	--	--
		LEA Intermediate	10	27	13 (6)[a]	-13 (-6)	0(0)	0 <0>[c]
		SCA Stringent	25	47	24 (11)	47 (21)	71 (32)	24 < 25>
		LNB Stringent	25	[47][b]	[24 (11)]	[47 (21)]	[71 (32)]	[24 < 25>]
		Ammonia Injection Stringent	25	[237]	[125]	[82]	[205]	[70 < 74>]
	117 (400)	No Controls SIP Moderate	--	--	--	--	--	--
		LEA Intermediate	10	44	12 (5)[a]	-13 (-6)	-2(-1)	0.6<0.7> [c]
		SCA Stringent	25	78	21 (9)	46 (21)	67 (30)	22 < 24>
		LNB Stringent	25	[78]	[21 (9)]	[46 (21)]	[67 (30)]	[22 <24>]
		Ammonia Injection Stringent	25	[472]	[125]	[82]	[205]	[70 <74>]

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mills/10^6 Btu heat input.

Continued

T-1549

TABLE 4-2. Concluded

System				Estimated Incremental Costs				
Standard Boilers					Annualized Costs			
					Fixed Costs	Operating Costs	Total Costs	
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 $	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{\text{GJ input}}$
Spreader Stoker	44 (150)	No Controls SIP Moderate	--	--	--	--	--	--
		LEA Intermediate	1	22	16 (7)[a]	-5 (-2)	11 (5)	3 <3>[c]
		SCA Stringent	20	22	16 (7)	4 (2)	20 (9)	6 <7>
Spreader Stoker	25 (85)	No Controls SIP	--	--	--	--	--	--
		SCA Moderate	20	17	22 (10)	5 (2)	27 (12)	8 <8>
		Ammonia Injection Stringent	55	[102][b]	[133 (60)]	[90 (40)]	[223 (100)]	[71 <75>]
Chain Grate Stoker	22 (75)	No Controls SIP Intermediate	--	--	--	--	--	--
		LEA Stringent	10	17	26 (12)	-10 (-4)	16 (8)	5 <5>
Underfeed Stoker	9 (30)	No controls SIP Intermediate	--	--	--	--	--	--
		LEA Stringent	10	14	54 (24)	-6 (-3)	48 (21)	15 <16>

T-1549

[a] Numbers in parentheses are mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mill/10^6 Btu heat input.

TABLE 4-3. ESTIMATED COST-EFFECTIVENESS AND IMPACTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR NEW COAL-FIRED BOILERS

System				Impacts			
Standard Boilers		Type and Level of Control	Cost Effectiveness $/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Pulverized Coal	59 (200)	No Controls SIP Moderate	--	--	--	--	--
		LEA Intermediate	0	0.4	--	0	0
		SCA Stringent	0.3	0.8	0.8	0.6	0.6
		LNB Stringent	[0.3][c]	[0.8]	[0.8]	[0.6]	[0.6]
		Ammonia Injection Stringent	[1.0]	[4.0]	[4.0]	[2.0]	[2.0]
	117 (400)	No Controls SIP Moderate	--	--	--	--	--
		LEA Intermediate	0	0.4	--	0	0
		SCA Stringent	0.3	0.8	0.8	0.6	0.6
		LNB Stringent	[0.3][c]	[0.8]	[0.8]	[0.6]	[0.6]
		Ammonia Injection Stringent	[1.0]	[4.0]	[4.0]	[2.0]	[2.0]

Continued

T-1562

[a] Cost of boiler only.
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

TABLE 4-3. Concluded

System				Impacts			
Standard Boilers		Type and Level of Control	Cost Effectiveness $/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Spreader Stoker	44 (150)	No Controls SIP Moderate	--	--	--	--	--
		LEA Intermediate	1.6	0.5	0.5	0.1	0.1
		SCA Stringent	0.1	0.5	0.5	0.1	0.1
Spreader Stoker	25 (85)	No Controls SIP	--	--	--	--	--
		SCA Moderate	0.2	0.7	0.7	0.2	0.2
		Amonia Injection Stringent	[0.5]	[5.0]	[5.0]	[2.5]	[2.5]
Chain Grate Stoker	22 (75)	No Controls SIP Intermediate	--	--	--	--	--
		LEA Stringent	0.4	1.2	1.2	0.2	0.2
Underfeed Stoker	9 (30)	No Controls SIP Intermediate	--	--	--	--	--
		LEA Stringent	0.6	1.5	1.5	0.2	0.2

[a] Cost of boiler only.
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

T-1562

TABLE 4-4. ESTIMATED COSTS OF CANDIDATE CONTROL TECHNIQUES FOR RETROFITTED COAL-FIRED BOILERS

System				Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 $	Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)				Fixed Costs	Operating Costs	Total Costs	
					$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{\text{GJ input}}$
Pulverized Coal	59 (200)	No Controls SIP Moderate	--	--	--	--	--	--
		LEA Intermediate	10	30	16 (7)[a]	-12 (-5)	4 (2)	1 <1>[c]
		SCA Stringent	25	70	37 (17)	59 (27)	96 (44)	33 <35>
		LNB Stringent	25	[70[b]]	[35 (16)]	[60 (27)]	[95 (43)]	[32 <34>]
		Ammonia Injection Stringent	25	[237]	[125 (57)]	[82 (37)]	[205 (93)]	[70 <73>]
	117 (400)	No Controls SIP Moderate	--	--	--	--	--	--
		LEA Intermediate	10	50	13 (6)[a]	-13 (-6)	0 (0)	0 <0>[c]
		SCA Stringent	25	118	31 (14)	57 (26)	88 (40)	29 <31>
		LNB Stringent	25	[118[b]]	[31 (14)]	[57 (26)]	[88 (40)]	[29 <31>]
		Ammonia Injection Stringent	25	[237]	[125 (57)]	[82 (37)]	[205 (93)]	[70 <73>]

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mills/10^6 Btu heat input.

Continued

T-1550

TABLE 4-4. Concluded

System					Estimated Incremental Costs			
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 $	Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)				Fixed Costs	Operating Costs	Total Costs	
					mills/10^3 kg steam	mills/10^3 kg steam	mills/10^3 kg steam	mills/GJ input
Spreader Stoker	44 (150)	No Controls SIP Moderate	--	--	--	--	--	--
		LEA Intermediate	1	25	18 (8)[a]	-3 (-1)	15 (7)	5 <5>[c]
		SCA Stringent	20	25	18 (8)	5 (2)	23 (10)	7 <7>
Spreader Stoker	25 (85)	No Controls SIP	--	--	--	--	--	--
		SCA Moderate	20	20	26 (12)	7 (3)	33 (15)	11 <11>
		Ammonia Injection Stringent	55	[100][b]	[131 (59)]	[88 (40)]	[220 (100)]	[70 <74>]
Chain Grate	22 (75)	No Controls SIP Intermediate	--	--	--	--	--	--
		LEA Stringent	10	20	30 (14)	-10 (-4)	20 (10)	6 <6>
Underfeed Stoker	9 (30)	No Controls SIP Intermediate	--	--	--	--	--	--
		LEA Stringent	15	14	54 (24)	-4 (-2)	50 (23)	16 <17>

T-1550

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mills/10^6 Btu heat input.

TABLE 4-5. ESTIMATED COST-EFFECTIVENESS AND IMPACTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR RETROFITTED COAL-FIRED BOILERS

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effectiveness $/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Pulverized Coal	59 (200)	LEA Intermediate	0.1	0.5	0.5	0	0
		SCA Stringent	0.5	1.2	1.2	0.8	0.8
		LNB Stringent	[0.4][c]	[1.2]	[1.2]	[0.8]	[0.8]
		Ammonia Injection Stringent	[1.0]	[4.0]	[4.0]	[2.0]	[2.0]
	117 (400)	LEA Intermediate	0	0.5	0.5	0	0
		SCA Stringent	0.4	1.2	1.2	0.8	0.8
		LNB Stringent	[0.4][c]	[1.2]	[1.2]	[0.8]	[0.8]
		Ammonia Injection Stringent	[1.0]	[4.0]	[4.0]	[2.0]	[2.0]

[a] Cost of boiler only.
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

Continued

T-1563

TABLE 4-5. Concluded

System			Impacts				
Standard Roilers		Type and Level of Control	Cost Effectiveness $/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Spreader Stoker	44 (150)	No Controls SIP Moderate	--	--	--	--	--
		LEA Intermediate	2.4	0.6	0.6	0.1	0.1
		SCA Stringent	0.2	0.6	0.6	0.2	0.2
Spreader Stoker	25 (85)	No Controls SIP	--	--	--	--	--
		SCA Moderate	0.2	1.0	1.0	0.3	0.3
		Amonia Injection Stringent	0.5[c]	5.0	5.0	2.5	2.5
Chain Grate Stoker	22 (75)	No Controls SIP Intermediate	--	--	--	--	--
		LEA Stringent	0.5	1.4	1.4	0.2	0.2
Underfeed Stoker	9 (30)	No Controls SIP Intermediate	--	--	--	--	--
		LEA Stringent	0.7	1.5	1.5	0.2	0.2

[a] Cost of boiler only.
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

T-1563

4.2.1 New Facilities

For pulverized coal-fired boilers, controls are not needed to reach SIP or moderate levels (301 ng/J). To achieve intermediate levels (258 ng/J), low excess air can sometomes be used which should not raise the cost of generating steam. Staged combustion through overfire air operation may allow stringent control levels to be met and could increase steam cost by about 0.5 percent. Low NO_x burners or ammonia injection may be needed to reach stringent control levels. Since both techniques are only in the development stage, only rough cost estimates can be given. However, LNB will probably not cost any more than OFA (References 4-1, 4-16). Low NO_x burners will most likely have a smaller energy penalty than OFA. Furthermore, low NO_x burner windbox modification and any additional burner cost will probably be no more than installing OFA ports. Ammonia injection prices were based on a utility boiler report (References 4-4 and 4-5) and have been extrapolated to industrial boiler size. Because industrial boiler loads fluctuate more than those of utility boilers, the cost of an NH_3 injection system per kilowatt should be higher for industrial boilers than utility boilers, which operate at more constant loads. Specifically, the ammonia injection system will probably have a higher unit cost since it may require several injection ports and a control system for switching between the ports. Using the utility boiler costs, ammonia injection is estimated to raise the price of steam by over 2 percent.

Large size spreader stokers need controls to reach an intermediate NO_x level (258 ng/J) and low excess air operation should be sufficient which would minimally affect the steam price. Overfire air can be used to achieve the even tighter stringent control levels (215 ng/J) which may raise the price of steam slightly. Stokers unlike pulverized coal units, normally have OFA ports as smoke control devices so there is no incremental charge for these ports and no additional fan power requirement. This assumes that the OFA ports need not be relocated for better NO_x control. Using more LEA than is needed to reach the NO_x control level can reduce the cost of steam. However, this can only be done where process operation limitations permit. The smaller size spreader stokers (<29 MW heat input) must meet more rigid control levels. To meet moderate levels (215 ng/J), OFA can be used which would raise steam costs slightly as was the case for the larger size stokers. Ammonia injection should achieve stringent control levels (129 ng/J) but, using utility boiler price estimates to give a gross estimate, steam cost can increase by about 2.5 percent which is a very large increase when compared to the other control techniques. Based on the only two tests reported, chain grate stokers only need controls to meet stringent control levels and LEA is recommended. Underfeed stokers only need control to reach stringent levels and LEA is recommended. Low excess air operation would raise steam cost slightly, but using even lower excess air than is needed to reach the control level may lower the steam price, if process operation limitations will permit.

4.2.2 Modified and Reconstructed Facilities

It is usually cheaper to modify a unit in the design phase than to retrofit after installation. Also, since retrofit costs are more site dependent than modifications to new units, retrofit cost estimates have a larger error than estimates for original equipment. Retrofitted controls would probably not be as efficient as original equipment. Therefore where OFA is used in Tables 4-4 and 4-5, the thermal efficiency is assumed to decrease by 0.25 percent. Ammonia injection costs are assumed to be the same for retrofitted units as for new ones. In general, NO_x control costs show the same trends for retrofitted as for new units.

4.3 CONTROL COSTS FOR OIL-FIRED BOILERS

The estimated incremental cost of NO_x controls for new boilers firing residual oil and distillate oil are shown in Tables 4-6, 4-7, 4-8, and 4-9. Since residual oil-fired units require different control methods than distillate oil-fired boilers, they are listed separately. Although boiler costs are about the same for both oils, residual oil firing requires more fuel handling equipment which raises the cost of the steam plant. The prices listed in the tables are engineering estimates based on vendor quotes and published costs (References 4-9, 4-10, 4-11, 4-12, 4-14, and 4-17 through 4-20). Tables 4-10, 4-11, 4-12, and 4-13 list the estimated costs for retrofitted boilers. Again, using lower excess air than is required to meet a control level can minimize the cost impact where process operation permits. Figures 4-2 and 4-3 show plots of annualized estimated control costs for new oil-fired boilers.

TABLE 4-6. ESTIMATED COSTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR NEW RESIDUAL OIL-FIRED BOILERS

System				Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost	Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)				Fixed Costs	Operating Costs	Total Costs	
				10^3 \$	$\frac{\text{mills}}{10^3\ \text{kg steam}}$	$\frac{\text{mills}}{10^3\ \text{kg steam}}$	$\frac{\text{mills}}{10^3\ \text{kg steam}}$	$\frac{\text{Mills}}{\text{GJ input}}$
Firetube	4.4 (15)	No Controls SIP Moderate	--	--	--	--	--	--
		LEA Intermediate	5	9	91 (41)[a]	-21 (-10)	70 (31)	22 < 24 >[c]
		SCA Stringent	25	19	193 (88)	117 (53)	310 (141)	99 <105 >
		LNB Stringent	25	[19][b]	[195 (88)]	[120 (54)]	[310 (141)]	[99 <105 >]
Watertube	8.8 (30)	LEA SIP Moderate	20	12	45 (20)	-68 (-31)	-23 (-11)	-7 <-8 >
		SCA Intermediate	35	22	82 (37)	89 (40)	171 (78)	55 < 58>
		LNB Stringent	45	[22]	[82 (37)]	[89 (40)]	[171 (78)]	[55 < 58 >]
		Ammonia Injection Stringent	45	[72]	[270 (122)]	[93 (42)]	[363 (165)]	[117 < 123 >]

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mills/10^6 Btu heat input.

Continued

T-1551

TABLE 4-6. Concluded

System				Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost	Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)				Fixed Costs	Operating Costs	Total Costs	
				10^3 $	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{Mills}}{\text{GJ input}}$
Watertube	44 (150)	LEA SIP Moderate	20	17	12 (5)	-75 (-34)	-63 (-29)	-20 <-28>
		SCA Intermediate	35	32	23 (10)	80 (36)	103 (46)	33 < 34>
		LNB Stringent	45	[32]	[23 (10)]	[80 (36)]	[102 (46)]	[33 < 34>]
		Ammonia Injection Stringent	45	[182]	[133 (60)]	[90 (41)]	[223 (101)]	[72 < 75>]

T-1551

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] < > indicates units of mills/10^6 Btu heat input.

TABLE 4-7. ESTIMATED COST-EFFECTIVENESS AND IMPACTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR NEW RESIDUAL OIL-FIRED BOILERS

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effec- \$/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Firetube	4.4 (15)	No Controls SIP Moderate	--	--	--	--	--
		LEA Intermediate	2.3	8.7	8.7	0.2	0.2
		SCA Stringent	3.2	21.0	21.0	1.2	1.2
		LNB Stringent	[3.2][c]	[21.0]	[21.0]	[1.2]	[1.2]
Watertube	8.8 (30)	LEA SIP Moderate	--	3.0	--	-0.1	--
		SCA Intermediate	1.1	5.5	2.5	1.2	1.3
		LNB Stringent	[0.7]	[5.5]	[2.5]	[1.2]	[1.3]
		Ammonia Injection Stringent	[1.6]	[18.0]	[18.0]	[2.5]	[2.6]

Continued T-1564

[a] Cost of boiler only.
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

TABLE 4-7. Concluded

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effec- $/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Watertube	44 (150)	LEA SIP Moderate	--	1.9	--	-0.5	--
		SCA Intermediate	0.6	3.8	1.9	0.8	1.3
		LNB Stringent	[0.4]	[4.0]	[2.0]	[0.8]	[1.3]
		Ammonia Injection Stringent	[1.1]	[22.5]	[22.0]	[2.0]	[2.5]

T-1564

[a] Cost of boiler only.
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

TABLE 4-8. ESTIMATED COSTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR NEW DISTILLATE OIL-FIRED BOILERS

System				Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 \$	Annualized Costs			
					Fixed Costs	Operating Costs	Total Costs	
Type	Heat Input MW (10^6 Btu/hr)				$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{\text{GJ input}}$
Firetube	4.4 (15)	No Control SIP Moderate	--	--	--	--	--	--
		LEA Intermediate	10	9	91 (41)[a]	-26 (-12)	65 (29)	20 <21>[c]
		FGR Stringent	40	19	192 (87)	175 (80)	367 (167)	117 < 125 >
		LNB Stringent	40	[19][b]	[192 (87)]	[100 (45)]	[292 (132)]	[93 <99 >]
Watertube without an Air Preheater	29 (100)	No control SIP Intermediate	--	--	--	--	--	--
		FGR Stringent	15	26	30 (13)	139 (63)	170 (77)	54 <57 >
		LNB Stringent	15	[26]	[30 (13)]	[86 (39)]	[115 (52)]	[37 <27 >]
		SCA Stringent	15	26	30 (13)	86 (39)	116 (52)	36 <39 >

Continued

T-1552

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicate units of mills/10^6 Btu heat input.

TABLE 4-8. Continued

System				Estimated Incremental Costs				
Standard Boilers					Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 \$	Fixed Costs	Operating Costs	Total Costs	
					$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{\text{GJ input}}$
Watertube with Air Preheater	29 (100)	No Controls SIP	--	--	--	--	--	--
		LEA Moderate	5	14	16 (7)[a]	-19 (-9)	-3 (-2)	-1 < -1>[c]
		RAP Intermediate	30	2	2 (1)	130 (59)	132 (60)	42 < 44 >
		FGR Intermediate	30	26	29 (13)	135 (61)	164 (74)	54 < 57 >
		LNB Intermediate	30	[26][b]	[29 (13)]	[90 (41)]	[119 (54)]	[38 < 40 >]
		SCA Intermediate	30	26	29 (13)	84 (38)	113 (51)	36 < 38 >
		RAP & FGR Stringent	55	26	29 (13)	265 (120)	294 (133)	94 < 98 >
		RAP & LNB Stringent	55	[26]	[29 (13)]	[215 (98)]	[244 (111)]	[78 < 82 >]

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mills/10^6 Btu heat input.

Continued

T-1552

TABLE 4-8. Concluded

System				Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 $	Annualized Costs			
					Fixed Costs	Operating Costs	Total Costs	
Type	Heat Input MW (10^6 Btu/hr)				$\frac{\text{mills}}{10^3\text{ kg steam}}$	$\frac{\text{mills}}{10^3\text{ kg steam}}$	$\frac{\text{mills}}{10^3\text{ kg steam}}$	$\frac{\text{mills}}{\text{GJ input}}$
Watertube with Air Preheater	44 (150)	No Controls SIP	--	--	--	--	--	--
		LEA Moderate	5	17	12 (6)[a]	-19 (-9)	-7 (-3)	-2 < -2 >[c]
		RAP Intermediate	30	2	1 (1)	128 (58)	130 (59)	42 < 44 >
		FGR Intermediate	30	32	23 (11)	133 (60)	156 (71)	51 < 54 >
		LNB Intermediate	30	[32][b]	[23 (11)]	[82 (37)]	[105 (48)]	[34 < 36 >]
		SCA Intermediate	30	32	23 (11)	82 (37)	105 (48)	34 < 36 >
		RAP & FGR Stringent	55	32	23 (11)	260 (118)	284 (129)	93 < 98 >
		RAP & LNB Stringent	55	[32]	[23 (11)]	[219 (100)]	[243 (116)]	[80 < 84 >]

T-1552

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mills/10^6 Btu heat input.

TABLE 4-9. ESTIMATED COST-EFFECTIVENESS AND IMPACTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR NEW DISTILLATE OIL-FIRED BOILERS

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effec- \$/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Firetube	4.4 (15)	No Control SIP Moderate	--	--	--	--	--
		LEA Intermediate	2.3	9.0	9.0	0.2	0.2
		FGR Stringent	4.1	21.0	21.0	1.2	1.2
		LNB Stringent	[3.2][c]	[21.0]	[21.0]	[1.0]	[1.0]
Watertube without an Air Preheater	29 (100)	No Control SIP Intermediate	--	--	--	--	--
		FGR Stringent	4.4	8.0	8.0	1.8	1.8
		LNB Stringent	[3.0]	[8.0]	[8.0]	[1.2]	[1.2]
		SCA Stringent	3.0	8.0	8.0	1.2	1.2

[a] Cost of boiler only.
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

Continued

T-1565

TABLE 4-9. Continued

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effec- $/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Watertube with Air Preheater	29 (100)	No Controls SIP	--	--	--	--	--
		LEA Moderate		3.4	3.4	0	0
		RAP Intermediate	1.7	0	0	1.4	1.4
		FGR Intermediate	2.1	7.0	7.0	1.7	1.7
		LNB Intermediate	[1.4][c]	[7.0]	[7.0]	[1.2]	[1.2]
		SCA Intermediate	1.4	7.0	7.0	1.2	1.2
		RAP + FGR Stringent	2.0	7.0	7.0	3.1	3.1
		RAP + LNB Stringent	[1.7]	[7.0]	[7.0]	[2.6]	[2.6]

Continued

T-1565

[a] Cost of boiler only.

[b] Cost includes entire steam plant.

[c] Bracket indicates gross estimate.

TABLE 4-9. Concluded

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effec-tiveness $/kg NO$_x$ Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Watertube with Air Preheater	44 (150)	No Controls SIP	--	--	--	--	--
		LEA Moderate		3.4	3.4	0	0
		RAP Intermediate	1.6	0.1	0.1	1.3	1.3
		FGR Intermediate	2.0	5.0	5.0	1.6	1.6
		LNB Intermediate	[1.3][c]	[4.0]	[4.0]	[1.1]	[1.1]
		SCA Intermediate	1.3	4.0	4.0	1.1	1.1
		RAP + FGR Stringent	1.9	4.0	4.0	2.9	2.9
		RAP + LNB Stringent	[1.6]	[4.0]	[4.0]	[2.4]	[2.4]

[a] Cost of boiler only.
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

T-1565

TABLE 4-10. ESTIMATED COSTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR RETROFITTED RESIDUAL OIL-FIRED BOILERS

System				Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 $	Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)				Fixed Costs	Operating Costs	Total Costs	
					mills/10^3 kg steam	mills/10^3 kg steam	mills/10^3 kg steam	mills/GJ input
Firetube	4.4 (15)	No Controls SIP Moderate	--	--	--	--	--	--
		LEA Intermediate	5	10	102 (46)[a]	-14 (-6)	88 (40)	28 <30>[c]
		SCA Stringent	25	30	304 (138)	170 (77)	475 (216)	152 <161>
		LNB Stringent	25	[30][b]	[300 (136)]	[170 (77)]	[475 (216)]	[152 <161>]
Watertube	8.8 (30)	LEA SIP Moderate	20	14	52 (24)	-66 (-30)	-14 (-6)	-4 <-5>
		SCA Intermediate	35	34	127 (58)	102 (46)	229 (104)	74 <78>
		LNB Stringent	45	[34]	[127 (58)]	[102 (46)]	[229 (104)]	[74 <78>]
		Ammonia Injection Stringent	45	[72]	[270 (122)]	[93 (42)]	[363 (165)]	[117 <123>]

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mills/10^6 Btu heat input.

T-1553

TABLE 4-10. Concluded

System				Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 \$	Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)				Fixed Costs	Operating Costs	Total Costs	
					mills/10^3 kg steam	mills/10^3 kg steam	mills/10^3 kg steam	mills/GJ input
Watertube	44 (150)	LEA SIP Moderate	20	20	15 (7)	-75 (-34)	-60 (-27)	-19 < -20 >
		SCA Intermediate	35	50	37 (17)	103 (47)	140 (64)	45 < 48 >
		LNB Stringent	45	[50]	[37 (17)]	[103 (47)]	[140 (64)]	[45 < 48 >]
		Ammonia Injection Stringent	45	[180]	[170 (77)]	[90 (41)]	[250 (114)]	[80 < 85 >]

[a] Numbers in parentheses are in units of mills/10^3 lb steam.

[b] Bracket indicates gross estimate.

[c] <> indicates units of mills/10^6 Btu heat input.

T-1553

TABLE 4-11. ESTIMATED COST EFFECTIVENESS AND IMPACTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR RETROFITTED RESIDUAL OIL-FIRED BOILERS

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effec- \$/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Firetube	4.4 (15)	No Controls SIP Moderate	--	--	--	--	--
		LEA Intermediate	4.0	12.5	12.5	0.4	0.4
		SCA Stringent	5.2	27.5	27.5	1.9	1.9
		LNB Stringent	[5.2][c]	[38.0]	[38.0]	[2.0]	[2.0]
Watertube	8.8 (30)	LEA SIP Moderate		3.5	--	-0.1	--
		SCA Intermediate	1.5	8.5	5.0	1.6	1.7
		LNB Stringent	[0.9]	[8.5]	[5.0]	[1.6]	[1.7]
		Ammonia Injection Stringent	[1.6]	[18.0]	[18.0]	[2.5]	[2.6]

[a] Cost of boiler only

[b] Cost includes entire steam plant.

[c] Bracket indicates gross estimate.

Continued

T-1558

TABLE 4-11. Concluded

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effec- $/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Watertube	44 (150)	LEA SIP Moderate		2.5	--	-0.5	--
		SCA Intermediate	0.9	6.2	3.7	1.1	1.6
		LNB Stringent	[0.6]	[6.2]	[3.7]	[1.1]	[1.6]
		Ammonia Injection Stringent	[1.1]	[22.5]	[22.5]	[1.9]	[2.5]

T-1558

[a] Cost of boiler only
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

TABLE 4-12. ESTIMATED COSTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR RETROFITTED DISTILLATE OIL-FIRED BOILERS

System				Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 $	Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)				Fixed Costs	Operating Costs	Total Costs	
					$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{\text{GJ input}}$
Firetube	4.4 (15)	No Control SIP Moderate	--	--	--	--	--	--
		LEA Intermediate	10	10	102 (46)[a]	-20 (-9)	82 (37)	26 <27>[c]
		FGR Stringent	40	30	304 (138)	208 (94)	512 (230)	164 < 171 >
		LNB Stringent	40	[30][b]	[304 (138)]	[156 (71)]	[460 (209)]	[14 < 156 >]
Watertube without an Air Preheater	29 (100)	No controls SIP Intermediate	--	--	--	--	--	--
		FGR Stringent	15	40	46 (21)	144 (65)	190 (86)	61 < 64 >
		LNB Stringent	15	[40]	[46 (21)]	[92 (42)]	[140 (64)]	[45 < 47 >]
		OSC Stringent	15	40	46 (21)	92 (42)	138 (64)	44 < 47 >

Continued

T-1554

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mills/10^6 Btu heat input.

TABLE 4-12. Continued

System					Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost $10^3 \$$	Annualized Costs				
Type	Heat Input MW (10^6 Btu/hr)				Fixed Costs	Operating Costs	Total Costs		
					mills / 10^3 kg steam	mills / 10^3 kg steam	mills / 10^3 kg steam	mills / GJ input	
Watertube with an Air Preheater	29 (100)	No Control SIP	--	--	--	--	--	--
		LEA Moderate	5	15	17 (8)[a]	-17 (-8)	0	0
		RAP Intermediate	30	2	2 (1)	130 (59)	132 (60)	44 < 47 >
		FGR Intermediate	30	40	45 (20)	139 (63)	185 (84)	63 < 66 >
		LNB Intermediate	30	[40][b]	[45 (20)]	[90 (41)]	[135 (61)]	[46 < 48 >]
		SCA Intermediate	30	40	45 (20)	88 (40)	135 (61)	46 < 48 >
		RAP + FGR Stringent	55	40	45 (20)	269 (122)	315 (143)	107 < 113 >
		RAP + LNB Stringent	55	[40]	[45 (20)]	[220 (100)]	[265 (120)]	[90 < 95 >]

Continued

T-1554

[a] Numbers in parentheses are in units of mills/10^3 lb steam.

[b] Bracket indicates gross estimate.

[c] <> indicates units of mills/10^6 Btu heat input.

TABLE 4-12. Concluded

System				Estimated Incremental Costs					
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 $	Annualized Costs				
Type	Heat Input MW (10^6 Btu/hr)				Fixed Costs	Operating Costs	Total Costs	
					mills/10^3 kg steam	mills/10^3 kg steam	mills/10^3 kg steam	mills/GJ input
Watertube with an Air Preheater	44 (150)	No Control SIP	--	--	--	--	--	--
		LEA Moderate	5	19	14 (6)[a]	-18 (-8)	-4 (-2)	-1 < -1 >
		RAP Intermediate	30	2	1 (1)	130 (59)	132 (60)	44 < 47 >
		FGR Intermediate	30	62	45 (20)	139 (63)	185 (84)	63 < 66 >
		LNB Intermediate	30	[62][b]	[45 (20)]	[90 (41)]	[135 (61)]	[46 < 48 >]
		SCA Intermediate	30	62	45 (20)	88 (40)	135 (61)	46 < 48 >
		RAP + FGR Stringent	55	62	45 (20)	269 (122)	315 (143)	107 < 113 >
		RAP + LNB Stringent	55	[62]	[45 (20)]	[220 (100)]	[265 (120)]	[90 < 95 >]

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mills/10^6 Btu heat input.

T-1554

TABLE 4-13. ESTIMATED COST EFFECTIVENESS AND IMPACTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR RETROFITTED DISTILLATE OIL-FIRED BOILERS

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effectiveness \$/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Firetube	4.4 (15)	No Control SIP Moderate	--	--	--	--	--
		LEA Intermediate	4.3	12.5	12.5	0.3	0.3
		FGR Stringent	6.0	37.5	37.5	1.8	1.8
		LNB Stringent	[5.4][c]	[37.5]	[37.5]	[1.6]	[1.6]
Watertube without an Air Preheater	29 (100)	No Controls SIP Intermediate	--	--	--	--	--
		FGR Stringent	5.0	13.0	13.0	2.0	2.0
		LNB Stringent	[3.6]	[13.0]	[13.0]	[1.5]	[1.5]
		SCA Stringent	3.6	13.0	13.0	1.5	1.5

Continued T-1559

[a] Cost of boiler only
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

TABLE 4-13. Continued

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effec-tiveness $/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Watertube with an Air Preheater	29 (100)	No Control SIP	--	--	--	--	--
		LEA Moderate	0	4.0	4.0	0	0
		RAP Intermediate	1.7	0	0	1.4	1.4
		FGR Intermediate	2.4	11.0	11.0	2.0	2.0
		LNB Intermediate	[1.7][c]	[11.0]	[11.0]	[1.4]	[1.4]
		SCA Intermediate	1.7	11.0	11.0	1.4	1.4
		RAP + FGR Stringent	2.1	11.0	11.0	3.4	3.4
		RAP + LNB Stringent	[1.8]	[11.0]	[11.0]	[2.9]	[2.9]

[a] Cost of boiler only

[b] Cost includes entire steam plant.

[c] Bracket indicates gross estimate.

Continued

T-1559

TABLE 4-13. Concluded

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effec-tiveness \$/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Watertube with an Air Preheater	44 (150)	No Control SIP	--	--	--	--	--
		LEA Moderate	0	4.0	4.0	0	0
		RAP Intermediate	1.7	0	0	1.4	1.4
		FGR Intermediate	2.4	11.0	11.0	2.0	2.0
		LNB Intermediate	[1.7][c]	[11.0]	[11.0]	[1.4]	[1.4]
		SCA Intermediate	1.7	11.0	11.0	1.4	1.4
		RAP + FGR Stringent	2.1	11.0	11.0	3.4	3.4
		RAP + LNB Stringent	[1.8]	[11.0]	[11.0]	[2.9]	[2.9]

T-1559

[a] Cost of boiler only
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

4.3.1 New Facilities

For the typical residual oil-fired firetube boiler to achieve intermediate NO_x emission levels (108 ng/J) low excess air (LEA) is recommended. This control technique can raise the price of steam by about 0.2 percent. However, even lower excess air over that needed to achieve the emission level can lower the impact on steam cost. Staged combustion (SCA) or low NO_x burners (LNB) are recommended techniques for reaching stringent control levels (86 ng/J). Staged combustion may raise the price of steam by over 1 percent and as already noted, LNB should probably have a smaller effect on steam cost than SCA does. Recall that this is because LNB are expected to have a smaller incremental capital cost and also have a smaller energy impact. At present a true estimate of the cost of LNB can not be made and thus LNB are assumed to be priced the same as SCA operation.

For the typical watertube boiler firing residual oil, low excess air is recommended for reaching SIP or moderate control levels (129 ng/J); LEA has the additional benefit of lowering steam cost. Staged combustion can be used to meet intermediate control levels (108 ng/J) but it may raise the price of steam by over 1 percent. Recall that the effect of staged combustion (overfire air or sidefire air) on thermal efficiency depends on port location and the fuel being fired; thus the exact cost impact of the SCA technique will depend on the air port location and the fuel being fired. If only one type of fuel is fired, it would be possible to optimize the location of the air port and possibly decrease the effect on steam cost. Meeting stringent control levels requires either LNB or ammonia injection, both of which have already been described. Ammonia injection costs are based on extrapolated utility prices and low NO_x burner costs are assumed to be no more than SCA costs. Since both methods (LNB and NH_3 injection) are in the development stage, the costs estimates may have large errors.

The recommended control methods for a firetube boiler firing distillate oil are LEA for intermediate levels and flue gas recirculation (FGR) or LNB for stringent levels. Increased fan power requirements for FGR makes it a costly technique for a typical distillate oil-fired firetube boiler. Although LNB are estimated to cost less than FGR, FGR is presently available, while low NO_x burners are still in the development stage.

The larger watertube boilers firing distillate oil are divided between those with and without an air preheater because the units with air preheaters emit more NO_x (see Section 3). Economizers are recommended over air preheaters as a device for increasing thermal efficiency since they raise efficiency without raising NO_x emission levels. Watertube boilers without air preheaters can use FGR, LNB, or SCA to reach stringent control levels. Staged combustion is estimated to have a smaller effect on steam cost than FGR but to allow for fuel switching, SCA may require several air port locations, which may be impractical. Again LNB are estimated to cost no more than SCA and probably less.

Watertube boilers with air preheaters can use LEA to reach moderate control levels without raising steam costs. Achieving intermediate control levels would require RAP, FGR, LNB, or SCA. Low NO_x burners should have the least economic impact of these four methods. Reduced air preheat is the easiest to implement but the thermal efficiency gained by installing the air preheater is lost. Again SCA should have a smaller economic impact than FGR if the need for several air port locations to allow for fuel switching does not make SCA impractical. To reach stringent control levels, RAP + FGR or RAP + LNB can be used. The high costs of these methods strongly suggest that economizers be used whenever possible instead of air preheaters. Low NO_x burners can have a smaller economic impact than is noted in the table but RAP + LNB would still be a costly technique due to the loss in thermal efficiency with RAP operation. The use of LEA and LNB with an economizer instead of an air preheater may result in lower steam costs and lower NO_x emissions.

4.3.2 Modified and Reconstructed Facilities

Firetube boilers are relatively more expensive on a percent basis to retrofit since their initial cost is not very high. For both residual and distillate oils, achieving stringent control levels can raise the steam costs by over 2 percent. The control costs are also high for firetube boilers because of the small base to spread modification costs over. It also costs more to retrofit watertube boilers than to include the emission control system in the original design.

4.4 CONTROL COSTS FOR NATURAL GAS-FIRED BOILERS

The control costs for natural gas-fired boilers discussed in this section are also engineering estimates based on published costs and manufacturer estimates (References 4-9 through 4-12, 4-14, and 4-17 through 4-20). Since most of the control methods have already been discussed, they are only briefly covered here. In all cases, LEA operation is recommended to lower the cost impact. Tables 4-14, 4-15, 4-16, and 4-17 list cost estimates for new and retrofitted units.

4.4.1 New Facilities

Firetube boilers firing natural gas meet all recommended NO_x emission levels without control systems. For watertube boilers again, economizers are recommended over air preheaters. Watertube boilers without air preheaters only need LEA operation to meet stringent NO_x control levels, possibly reducing steam costs slightly. Watertube boilers with air preheaters will require additional controls to meet all recommended emission levels.

Watertube boilers with air preheaters need RAP, FGR, SCA or LNB to meet SIP or moderate control levels (86 ng/J). Using RAP deletes the efficiency gained by the air preheaters, but RAP may still be less costly than FGR. Staged combustion or LNB should have smaller cost impacts than RAP or FGR but LNB are still being developed and SCA may be impractical because of fuel switching problems as was discussed earlier. Flue gas recirculation is not as effective for controlling NO_x emissions from residual oil-fired boilers and can limit the oils that can be fired when natural gas is not available. For achieving intermediate control levels, RAP + OFA/SFA can be used but it can raise steam prices by over 3 percent. The least expensive method for reaching stringent control levels is RAP + LNB. The system of RAP + FGR can also be used, which may raise the price of steam by over 4 percent. Alternatively, RAP + NH_3 injection can be used, but it is the most costly of these controls and because of load fluctuations and possible NH_3 emissions, it may prove impractical.

4.4.2 Modified and Reconstructed Facilities

Reducing air preheat on an existing boiler equipped with an air preheater is less cost-effective than using an economizer instead of an air preheater on a new unit. The other control techniques are expected to

TABLE 4-14. ESTIMATED COSTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR NEW NATURAL GAS-FIRED BOILERS

System				Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 $	Annualized Costs			
					Fixed Costs	Operating Costs	Total Costs	
Type	Heat Input MW (10^6 Btu/hr)				$\frac{\text{mills}}{10^3\text{ kg steam}}$	$\frac{\text{mills}}{10^3\text{ kg steam}}$	$\frac{\text{mills}}{10^3\text{ kg steam}}$	$\frac{\text{mills}}{\text{GJ input}}$
Firetube	4.4 (15)	No Control SIP Stringent	--	--	--	--	--	--
Watertube without an Air Preheater	29 (100)	No Controls SIP Intermediate	--	--	--	--	--	--
		LEA Stringent	5	14	16 (7)[a]	-25 (-11)	-9 (-4)	-3 <-4>[c]
Watertube with an Air Preheater	29 (100)	RAP SIP Moderate	25	2	2 (1)	113 (51)	115 (52)	38 < 41 >
		FGR SIP Moderate	25	26	29 (13)	120 (54)	150 (67)	51 < 53 >
		SCA SIP Moderate	25	26	29 (13)	69 (31)	98 (44)	33 < 36 >
		LNB SIP Moderate	25	[26][b]	[29 (13)]	[69 (31)]	[98 (44)]	[33 < 35 >]
		RAP + SCA Intermediate	40	26	29 (13)	183 (83)	212 (96)	72 < 76 >

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[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mills/10^6 Btu heat input.

Continued

T-1555

TABLE 4-14. Concluded

System				Estimated Incremental Costs				
Standard Boilers					Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 $	Fixed Costs	Operating Costs	Total Costs	
					mills / 10^3 kg steam	mills / 10^3 kg steam	mills / 10^3 kg steam	mills / GJ input
Watertube with an Air Preheater	29 (100)	RAP + FGR Stringent	60	26	29 (13)[a]	233 (106)	262 (119)	89 <94 >
		RAP + LNB Stringent	60	[26][b]	[29 (13)]	[182 (82)]	[210 (95)]	[71 <75>]
		RAP + NH_3 Injection Stringent	60	[118]	[132 (60)]	[201 (91)]	[333 (151)]	[113 <118>]
	44 (150)	RAP SIP Moderate	30	2	2 (1)	111 (51)	113 (51)	37 <39>
		FGR SIP Moderate	30	32	23 (11)	117 (53)	141 (64)	46 <49>
		LNB SIP Moderate	30	[32][b]	[23 (11)]	[66 (30)]	[89 (41)]	[29 <31>]
		RAP + OSC Intermediate	45	32	23 (11)	179 (81)	203 (92)	67 <70>
	44 (150)	RAP + FGR Stringent	65	32	23 (11)[a]	229 (104)	252 (114)	83 <87>
		RAP + LNB Stringent	65	[32][b]	[23 (11)]	[179 (81)]	[202 (92)]	[66 <70>]
		RAP + NH_3 Injection Stringent	65	[182]	[133 (60)]	[199 (90)]	[332 (150)]	[109 <115>]

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <>indicates units of mills/10^6 Btu heat input.

T-1555

TABLE 4-15. ESTIMATED COST EFFECTIVENESS AND IMPACTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR NEW NATURAL GAS-FIRED BOILERS

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effectiveness $/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Firetube	4.4 (15)	No Control SIP Stringent	--	--	--	--	--
Watertube without an Air Preheater	29 (100)	No Controls SIP Intermediate	--	--	--	--	--
		LEA Stringent		4	4	-0.2	-0.2
Watertube with an Air Preheater	29 (100)	RAP SIP Moderate	1.5	7	--	1.8	--
		FGR SIP Moderate	2.0	7	--	2.4	--
		SCA SIP Moderate	1.3	7	--	1.5	--
		LNB SIP Moderate	[1.3][c]	[7][c]	--	[1.5]	--
		RAP + SCA Intermediate	1.5	7	7	3.4	1.6

[a] Cost of boiler only

[b] Cost includes entire steam plant.

[c] Bracket indicates gross estimate.

Continued

T-1560

TABLE 4-15. Continued

System			Impacts				
Standard Boilers		Type and Level of Control	Effectiveness $/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Watertube with an Air Preheater	29 (100)	RAP + FGR Stringent	1.3	7	7	4.2	2.4
		RAP + LNB Stringent	[1.0][c]	[7]	[7]	[3.3]	[1.5]
		RAP + NH_3 Injection Stringent	[1.6]	[33]	[33]	[5.3]	[3.5]
Watertube with an Air Preheater	44 (150)	RAP SIP Moderate	1.1	7	--	1.8	--
		FGR SIP Moderate	1.4	7	--	2.4	--
		LNB SIP Moderate	[0.9][c]	[7][c]	--	[1.5]	--
		RAP + SCA Intermediate	1.2	7	7	3.4	1.6

Continued

T-1560

[a] Cost of boiler only
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

TABLE 4-15. Concluded

System			Impacts				
Standard Boilers		Type and Level of Control	Cost Effectiveness $/kg NO_x$ Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Watertube with an Air Preheater	44 (150)	RAP + FGR Stringent	1.1	7	7	4.2	2.4
		RAP + LNB Stringent	[0.9][c]	[7]	[7]	[3.3]	[1.5]
		RAP + NH_3 Injection Stringent	[1.4]	[33]	[33]	[5.3]	[3.5]

T-1560

[a] Cost of boiler only
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

TABLE 4-16. ESTIMATED COSTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR RETROFITTED NATURAL GAS BOILERS

System				Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 $	Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)				Fixed Costs	Operating Costs	Total Costs	
					$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{10^3 \text{ kg steam}}$	$\frac{\text{mills}}{\text{GJ input}}$
Firetube	4.4 (15)	No Controls SIP Stringent	--	--	--	--	--	--
Watertube without an Air Preheater	29 (100)	No Controls SIP Intermediate	--	--	--	--	--	--
		LEA Stringent	5	15	18 (8)[a]	-25 (11)	-7 (-3)	-2 < -2 >[c]
Watertube with an Air Preheater	29 (100)	RAP SIP Moderate	25	2	2 (1)	113 (51)	115 (51)	39 < 40 >
		FGR SIP Moderate	25	40	45 (20)	125 (57)	170 (77)	58 < 61 >
		SCA SIP Moderate	25	40	45 (20)	74 (34)	120 (54)	41 < 43 >
		LNB SIP Moderate	25	[40]	[45 (20)]	[74 (34)]	[120 (54)]	[41 < 43 >]
		RAP + SCA Intermediate	40	40	45 (20)	187 (85)	230 (104)	78 < 82 >

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mills/10^6 Btu heat input.

Continued

T-1556

TABLE 4-16. Continued

System					Estimated Incremental Costs			
Standard Boilers					Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 \$	Fixed Costs	Operating Costs	Total Costs	
					mills / 10^3 kg steam	mills / 10^3 kg steam	mills / 10^3 kg steam	mills / GJ input
Watertube with an Air Preheater	29 (100)	RAP + FGR Stringent	60	40	45 (20)[a]	237 (108)	280 (128)	95 < 101>[c]
		RAP + LNB Stringent	60	[40][b]	[45 (20)]	[185 (84)]	[230 (104)]	[78 < 82 >]
		RAP + NH_3 Injection Stringent	60	[116]	[130 (59)]	[201 (91)]	[330 (150)]	[112 < 118 >]
	44 (150)	RAP SIP Moderate	30	2	2 (1)	113 (51)	115 (51)	39 < 40 >
		FGR SIP Moderate	30	62	45 (20)	125 (57)	170 (77)	58 < 61 >
		LNB SIP Moderate	30	[62]	[45 (20)]	[74 (34)]	[120 (54)]	[41 < 43 >]
		RAP + SCA Intermediate	45	62	45 (20)	187 (85)	230 (104)	78 < 82 >

Continued

T-1556

[a] Numbers in parentheses are in units of mills/10^3 lb steam.
[b] Bracket indicates gross estimate.
[c] <> indicates units of mills/10^6 Btu heat input.

TABLE 4-16. Concluded

System				Estimated Incremental Costs				
Standard Boilers		Type and Level of Control	Control Effectiveness Percent	Capital Cost 10^3 $	Annualized Costs			
Type	Heat Input MW (10^6 Btu/hr)				Fixed Costs	Operating Costs	Total Costs	
					$\frac{\text{mills}}{10^3\text{ kg steam}}$	$\frac{\text{mills}}{10^3\text{ kg steam}}$	$\frac{\text{mills}}{10^3\text{ kg steam}}$	$\frac{\text{mills}}{\text{GJ input}}$
Watertube with an Air Preheater	44 (150)	RAP + FGR Stringent	65	62	45 (20)[a]	237 (108)	280 (128)	95 <101>[c]
		RAP + LNB Stringent	65	[62][b]	[45 (20)]	[185 (84)]	[230 (104)]	[78 <82>]
		RAP + NH_3 Injection Stringent	65	[182]	[130 (59)]	[201 (91)]	[330 (150)]	[112 <118>]

T-1556

[a] Numbers in parentheses are in units of mills/10^3 lb steam.

[b] Bracket indicates gross estimate.

[c] <> indicates units of mills/10^6 Btu heat input.

TABLE 4-17. ESTIMATED COST EFFECTIVENESS AND IMPACTS OF CANDIDATE NO_x CONTROL TECHNIQUES FOR RETROFITTED NATURAL GAS-FIRED BOILERS

System			Cost Effectiveness	Impacts			
Standard Boilers		Type and Level of Control	$/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Firetube	4.4 (15)	No Controls SIP Stringent	--	--	--	--	--
Watertube without an Air Preheater	29 (100)	No Controls SIP Intermediate	--	--	--	--	--
		LEA Stringent	--	5	5	-0.1	-0.1
Watertube with an Air Preheater	29 (100)	RAP SIP Moderate	1.5	0	--	1.8	--
		FGR SIP Moderate	2.3	11	--	2.7	--
		SCA SIP Moderate	1.6	11	--	1.9	--
		LNB SIP Moderate	[1.6][c]	[11]	--	[1.9]	--
		RAP + SCA Intermediate	1.7	11	11	3.7	1.9

Continued

T-1561

[a] Cost of boiler only
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

TABLE 4-17. Continued

System			Cost Effectiveness	Impacts			
Standard Boilers		Type and Level of Control	\$/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Watertube with an Air Preheater	29 (100)	RAP + FGR Stringent	1.4	7	7	4.5	2.7
		RAP + LNB Stringent	[1.1]	[7]	[7]	[3.7]	[1.9]
		RAP + NH_3 Injection Stringent	[1.6]	[33]	[33]	[5.3]	[3.5]
Watertube with an Air Preheater	44 (150)	RAP SIP Moderate	1.1	0	--	1.8	--
		FGR SIP Moderate	1.7	11	--	2.7	--
		LNB SIP Moderate	[1.2][c]	[11]	--	[1.9]	--
		RAP + SCA Intermediate	1.3	11	11	3.7	1.9

Continued T-1561

[a] Cost of boiler only

[b] Cost includes entire steam plant.

[c] Bracket indicates gross estimate.

TABLE 4-17. Concluded

System			Cost Effectiveness	Impacts			
Standard Boilers		Type and Level of Control	\$/kg NO_x Reduced	Percent Increase in Capital Cost[a] Over		Percent Increase in Steam Cost[b] Over	
Type	Heat Input MW (10^6 Btu/hr)			Uncontrolled Boiler	SIP-Controlled Boiler	Uncontrolled Boiler	SIP-Controlled Boiler
Watertube with an Air Preheater	44 (150)	RAP + FGR Stringent	1.2	7	7	4.5	2.7
		RAP + LNB Stringent	[1.1]	[7]	[7]	[3.7]	[1.9]
		RAP + NH_3 Injection Stringent	[1.4]	[33]	[33]	[5.3]	[3.5]

T-1561

[a] Cost of boiler only
[b] Cost includes entire steam plant.
[c] Bracket indicates gross estimate.

give higher steam costs than RAP, as shown in Tables 4-16 and 4-17. The previous comments on control techniques for new units still apply here for retrofitted boilers.

4.5 SUMMARY

The primary contributions of combustion modification NO_x controls to steam cost changes are the equipment modification costs and changes in thermal efficiency and fan power demand. For firetube boilers annualized equipment costs are usually higher than costs due to efficiency or fan power demand changes. For watertube boilers, the opposite is usually true. For both firetube and watertube boilers, all costs are important and any factors that can lower any of these costs will be beneficial. In many cases, using the lowest possible excess air will lower the cost impact. Of course, the boiler should be designed to give the highest possible thermal efficiency and lowest fan power requirements. Careful design can result in better fuel efficiency than was assumed in the calculations for flue gas recirculation and staged combustion.

Of the NO_x controls covered, low excess air is the method recommended to be first considered since it can reduce fuel costs. Low NO_x burners are a promising technique since they should allow both low NO_x and LEA operation, and thus save fuel while lowering NO_x emissions. Staged combustion is the next best method, unless fuel switching problems make it impractical, since the optimal air port location is fuel dependent. If SCA cannot be used, FGR is the next most cost-effective technique. Ammonia injection is the least cost effective technique and load changing may make it very impractical. Also, whenever possible, an economizer is preferred over an air preheater as a fuel saving device since it does not raise NO_x levels.

In summary, combustion modification NO_x controls, once proven and demonstrated, should be a cost effective means of control for industrial boilers raising steam costs up to only 1 to 2 percent in most cases. However, the initial investment required, especially for small boilers, may be a large fraction of the cost of the boiler itself, up to 25 percent when controls are installed on a new boiler and up to 50 percent when retrofitting the controls on an existing boiler. Factory installed controls on new boilers should prove more cost effective than retrofit controls.

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SECTION 5

ENERGY IMPACT

This section discusses the energy impact of combustion modification techniques for controlling NO_x emissions from industrial boilers. The amount and type of energy required to operate each of the candidate emission control systems of Section III are identified. Where possible, these values are compared to the quantities and types of energy required by a typical facility, without any NO_x emission control system and one controlled to comply with average state regulations. These State Implementation Plan (SIP) regulations have been discussed elsewhere (Reference 5-1) and are summarized in Table 5-1.

TABLE 5-1. AVERAGE STATE IMPLEMENTATION PLAN REQUIREMENTS (REFERENCE 5-1)

Fuel	Level of Control, ng NO_2/J (lb/10^6Btu)
Coal	301 (0.7)
Oil	129 (0.3)
Gas	86 (0.2)

5.1 INTRODUCTION

The largest potential energy impact of combustion modification NO_x control techniques is their effect upon boiler thermal efficiency. Another significant source of energy impact is the change in fan power caused by these control techniques. Boiler control systems installed for low NO_x operation also increase electricity and instrument air requirements, but the energy impact is usually minimal.

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The changes in boiler efficiency discussed here are from actual tests on industrial size boilers as well as engineering estimates. These estimates were arrived at by extrapolating or interpolating results from tested boilers. Even for the boiler sizes where there were actual efficiency measurements, the scatter in the data still required that engineering judgment be used to estimate a typical value. Because only a few tests of short duration have been made, any long term effects have not been determined. Also, industrial boilers operate under fluctuating loads and small changes in boiler performance are not readily observable. Because an industrial boiler operates with little attention and loads fluctuate, fine tuning of the boiler is limited. This restricts operation efficiency and limits the effectiveness of NO_x control methods.

The following paragraphs present general comments on the energy impacts of candidate NO_x control systems:

- Low excess air (LEA);
- Staged combustion air (SCA)
  - Overfire air (OFA)
  - Sidefire air (SFA);
- Flue gas recirculation (FGR);
- Reduced air preheat (RAP);
- Low NO_x burners (LNB);
- Ammonia injection.

Sections 5.2, 5.3, and 5.4 further discuss the energy impacts on coal-, oil-, and gas-fired industrial boilers, respectively.

Operating a boiler under low excess air conditions decreases the total air flow through the boiler, and hence the sensible heat loss out the stack is minimized, increasing boiler thermal efficiency. When LEA is used alone, a smaller force draft fan could save additional energy, although this would only be a small savings. Low excess air operation would probably require an oxygen trim system, but that would consume only a minimal amount of energy. Thus, there is a large net gain in energy with low excess air operation.

Staged combustion via overfire air (OFA) or sidefire air (SFA) operation can increase the combustion air pressure drop because of additional duct work. Also, air flow would be increased if the amount of overfire air is greater than the reduction of air through the flame.

Therefore additional forced draft fan power is usually required with staged combustion. From utility boiler experience, energy losses of 0.1 percent of boiler heat input capacity are the maximum expected due to the larger forced draft fan (Reference 5-2). The effect on thermal efficiency depends on air port location and the amount of total air used with OFA or SFA operation. The air port must be located so that proper mixing of the unburned fuel and air can be achieved, maintaining combustion efficiency. If the amount of air through the OFA or SFA ports is no more than the decreased air through the flame, thermal efficiency, in theory, should not be hurt.

Flue gas recirculation (FGR) also requires more fan power. This increased fan power requirement is expected to be of the order of 0.25 percent of boiler heat input capacity, based on utility boiler experience (Reference 5-2). The 0.25 percent factor for industrial boilers is slightly higher than that for utility boilers, because of the former's proportionately more constrictive recirculation duct work. Flue gas recirculation may have a small effect on boiler thermal efficiency because FGR causes lower furnace temperatures which may decrease the amount of heat transferred to the water and steam.

Reduced air preheat (RAP) operation will usually lower the boiler's efficiency. Unless the boiler has an economizer with extra capacity, RAP operation will raise the flue gas temperature causing a greater loss of sensible heat from the boiler.

Low NO_x burners for industrial boilers are still in the development stage. Some low NO_x burners increase the pressure drop across the burner (References 5-3 through 5-6) and could require more fan power. In principle, low NO_x burners should not affect boiler thermal efficiency. A number will be given for energy use by LNB but that number is a very rough estimate.

Ammonia injection is another control technique under development. The process requires energy for the injectors and NH_3 handling equipment. There is also a slight energy loss due to the carrier gas.

All the comments given here are for typical boilers controlled to meet representative NO_x emission levels. The actual energy impact depends on the particular boiler and quantity of control used. Because of this, the uncertainty in the energy impact listed in the following tables is at least ±50 percent. Also as already mentioned, the following discussions are based on very limited data. First, energy impacts for coal-fired units are discussed, then oil-fired and gas-fired boilers. The control methods and control levels were described in Section 3.

5.2 ENERGY IMPACT OF CONTROLS FOR COAL-FIRED BOILERS

Most coal-fired industrial boilers are either stoker-fired or pulverized coal-fired. Only the larger sized industrial boilers are pulverized coal-fired; the stoker size range covers all industrial boilers. The discussion that follows on pulverized coal units relies heavily on utility boiler experience (Reference 5-2). Most of the data on stokers were collected by KVB, Battelle, and Acurex under EPA sponsored programs (References 5-7 through 5-13). All comments are based on these references unless otherwise stated. Whenever possible, LEA should be combined with other control methods to reduce any energy increase. Table 5-2 summarizes the energy impact on coal-fired boilers.

5.2.1 New Facilities

The two main methods of firing pulverized coal are tangential and single wall-fired units. Based on the limited number of tests, these two firing types give about the same emission levels and are thus treated together, as discussed in Section 3. Without any controls, the average pulverized coal-fired units can meet State Implementation Plan (SIP) levels of 301 ng/J and moderate control levels of 301 ng/J. For a pulverized coal unit to meet intermediate control levels (258 ng/J), LEA was recommended since it may decrease coal consumption by 0.5 percent. Soot could increase slightly, requiring a little more use of soot blowers, but this would be a minimal effect. To meet stringent control levels, staged combustion with OFA, may be required. This can result in a small additional fan power requirement of 0.1 percent and a small drop in thermal efficiency of 0.25 percent. Low NO_x burners (LNB) or ammonia injection may also be used to reach stringent control levels. The energy consumption is unknown for both methods and with LEA operation, consumption might even decrease. Some types of low NO_x burners (References 5-3, 5-4, 5-5, and 5-6) could require more fan power which would increase energy use. For ammonia injection, energy requirements for the injectors and NH_3 handling equipment would be minimal but the air compressor for

TABLE 5-2. ENERGY CONSUMPTION DUE TO NO_X CONTROL TECHNIQUES FOR COAL-FIRED BOILERS

System					Energy Consumption		
Standard Boiler							
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10^6 Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Pulverized Coal	59 (200)	No Control Device SIP Moderate	-- --	-- --	-- --	-- --	-- --
		Low Excess Air Intermediate	10	Coal	- 0.3 (- 1.0)	- 0.5	- 0.5
		Overfire Air Stringent	25	Electric or Steam Coal	0.06 (0.2) 0.15 (0.5) [d]	0.10 0.25 [d]	0.10 0.25 [d]
		Low NO_x Burners Stringent	25	Electric Coal	0.15 (0.5)	0.25	0.25
		Ammonia Injection Stringent	25	Electric	0.3 (1.0)	0.5	0.5
Pulverized Coal	117 (400)	No Control Device SIP Moderate	-- --	-- --	-- --	-- --	-- --
		Low Excess Air Intermediate	10	Coal	0.6	- 0.5	- 0.5

T-1439

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.

[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100

[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100

[d] Add figures for total energy consumption of control device

[e] Number is rough estimate

[f] Low excess air operation could lower energy impact

Continued

TABLE 5-2. Continued

System					Energy Consumption		
Standard Boiler							
Type	Heat Input MW (10⁶ Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10⁶ Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Pulverized Coal (continued)	117 (400)	Overfire Air Stringent	25	Electric or Steam Coal	0.1 (0.4) 0.3 (1.0) [d]	0.10 0.25 [d]	0.10 0.25 [d]
		Low NO_x Burners Stringent	25	Electric Coal	0.3 (1.0)[e,f]	0.25	0.25
		Ammonia Injection Stringent	25	Electric	0.6 (2.0)[e,f]	0.5	0.5
Spreader Stoker	44 (150)	No Control Device SIP Moderate	-- --	-- --	-- --	-- --	-- --
		Low Excess Air Intermediate	5	Coal	- 0.1 (- 0.4)	- 0.25	- 0.25
		Low Excess Air and Overfire Air Stringent	20	Electric Coal	None expected[f]	--	--

T-1439

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.

[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100

[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100

[d] Add figures for total energy consumption of control device

[e] Number is rough estimate

[f] Low excess air operation could lower energy impact

Continued

TABLE 5-2. Concluded

System					Energy Consumption		
Standard Boiler Type	Standard Boiler Heat Input MW (10^6 Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10^6 Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Spreader Stoker	25 (85)	No Control Device SIP	--	--	--	--	--
		Low Excess Air and Overfire Air Moderate	20	Electric Coal	None expected[f]	--	--
		Ammonia Injection Intermediate Stringent	35 55	Electric Coal	0.1 (0.4)[f]	0.5	0.5
Chain Grate Stoker	22 (75)	No Control Device SIP Intermediate	-- --	-- --	-- --	-- --	-- --
		Low Excess Air Stringent	8	Coal	- 0.11 (-0.4)	-0.5	-0.5
Underfeed Stoker	9 (30)	No Control Device SIP Intermediate	-- --	-- --	-- --	-- --	-- --
		Low Excess Air Stringent	15	Coal	- 0.04 (- 0.15)	- 0.5	- 0.5

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.

T-1439

[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100

[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100

[d] Add figures for total energy consumption of control device

[e] Number is rough estimate

[f] Low excess air operation could lower energy impact

the carrier gas could increase energy use by at least 0.25 percent (Reference 5-19).

Spreader stokers larger than 29 MW heat input require no controls to meet SIP or moderate control levels (301 ng/J). Only LEA operation is needed to meet intermediate levels of 258 ng/J, which could reduce coal consumption by 0.25 percent. Using even lower excess air than is required to meet the standard could lower fuel consumption even more. However, operational limitations may prevent such low excess air levels (see Section 3). Staged combustion air could be used to meet stringent control levels (215 ng/J). There is only a small fan power increase since stokers normally use some OFA as a smoke control method (baseline). Also thermal efficiency does not change; it could even increase by combining LEA with OFA. No controls are needed to meet SIP levels for spreader stokers less than 29 MW. But staged combustion is needed to meet moderate control levels (215 ng/J). Staged combustion would have the analogous energy impact on the smaller stokers as on the larger units. Ammonia injection is recommended to reach either intermediate (172 ng/J) or stringent (129 ng/J) control levels. This process has the same energy impact as for pulverized coal units.

Only two chain grate stoker tests have been reported, and based on that limited data, LEA control may be able to achieve the stringent control level (129 ng/J) with an energy savings of about 0.5 percent. The underfeed stokers tested needed no controls to meet SIP or intermediate control levels (172 ng/J). To reach stringent control levels, LEA operation is recommended, which could give an energy savings of at least 0.5 percent.

5.2.2 Modified and Reconstructed Facilities

Existing units with retrofitted NO_x controls should have about the same energy impact as new units. Because of the windbox design, retrofitted OFA ports might have larger pressure drops and require more fan power. The efficiency for pulverized units using OFA ports, depends on location. Since it might not be possible to put the air ports in the optimal spot on a retrofitted boiler, efficiency might be lowered. Also, a new boiler might be designed to operate under a lower excess air level than an existing one. Thus the energy impacts on an existing unit may be greater than those on a new unit. Since the actual energy impact will depend on the particular boiler being modified, the expected energy impact can not be quantified at this time.

5.3 ENERGY IMPACT OF CONTROLS FOR OIL-FIRED BOILERS

This discussion of the energy impact of combustion modifications for controlling NO_x emissions from oil-fired boilers is based on tests conducted by KVB and Ultrasystems (References 5-7, 5-8, 5-9, 5-14, 5-15, 5-17). As mentioned previously, these tests were all short term and the condition of the boiler was not always documented. Also the additional electricity and instrument air required to operate under low NO_x conditions are minimal, and these topics are not covered. Residual and distillate oil-fired boilers are discussed. The energy impacts on residual oil-fired boilers and distillate oil-fired boilers are summarized in Tables 5-3 and 5-4. Whenever possible, LEA operation should be used to increase boiler thermal efficiency and hence reduce energy consumption.

5.3.1 New Units

Firetube boilers firing residual oil need no controls to meet SIP or moderate control levels (129 ng/J). Low excess air operation can be used to achieve intermediate control levels, resulting in an oil savings of about 0.5 percent. Low NO_x burners or staged combustion is recommended to reach the next control level, stringent (86 ng/J). Low NO_x burner might require more fan power but since LNB is still in the development stage, their effect on fan power requirement is unknown. Their effect on thermal efficiency is expected to be minimal. The thermal efficiency in staged combustion depends on both the air port location and the fuel being fired. Efficiency will not be affected if the air port is in the proper location for the fuel being fired. Since this will not always be the case, an efficiency loss of 0.5 percent is assumed. Also additional fan power equal to about 0.10 percent of boiler heat input, could be needed.

Low excess air operation is needed to reach SIP or moderate control levels (129 ng/J) for watertube boilers firing residual oil. This control technique could result in a fuel savings of 1 percent. To achieve an intermediate control level, staged combustion can be used. Efficiency can increase or decrease depending on type of fuel used and air port location. Thermal efficiency could be decreased by 0.5 percent, and fan requirements could be increased. Low NO_x burners or ammonia injection

TABLE 5-3. ENERGY CONSUMPTION FOR NO_x CONTROL TECHNIQUES FOR RESIDUAL OIL-FIRED BOILERS

System					Energy Consumption		
Standard Boiler							
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10^6 Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Firetube	4.4 (15)	No Control Device SIP Moderate	-- --	-- --	-- --	-- --	-- --
		Low Excess Air Intermediate	5	Oil	-0.02 (-0.075)	-0.5	-0.5
		Low Excess Air and Overfire Air Stringent	25	Oil, Electric	0.02 (0.07) 0.004 (0.015) [d]	0.5 0.1 [d]	0.5 0.1 [d]
		Low NO_x Burners Stringent	25	Oil, Electric	0.01 (0.04)	0.25	0.25
Watertube	8.8 (30)	Low Excess Air SIP Moderate	20 20	Oil	-0.1 (-0.3)	-1.0	--
		Low Excess Air and Overfire or Side-fire Air Intermediate	35	Oil Electric or Steam	0.04 (0.15) 0.01 (0.03) [d]	0.5 0.1 [d]	1.5 0.1 [d]

T-1440

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.
[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100
[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100
[d] Add figures for total energy consumption of control device
[e] Number is rough estimate
[f] Low excess air operation could lower energy impact

Continued

TABLE 5-3. Concluded

System					Energy Consumption		
Standard Boiler							
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10^6 Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Watertube (continued)	8.8 (30)	Low NO_x Burners Stringent	45	Oil, Electric	0.02 (0.08)[e,f]	0.25	1.25
		Ammonia Injection Stringent	45	Oil, Electric	0.04 (0.15)[f]	0.5	1.5
Watertube	44 (150)	Low Excess Air SIP Moderate	20 20	Oil	-0.4 (-1.5)	-1.0	--
		Low Excess Air and Overfire or Side-fire Air Intermediate	35	Oil Electric or Steam	0.04 (0.15) 0.01 (0.03) } d	0.5 0.1 } d	1.5 0.1 } d
		Low NO_x Burners Stringent	45	Oil, Electric	0.1 (0.4)[e,f]	0.25	1.25
		Ammonia Injection Stringent	45	Oil, Electric	0.2 (0.8)[f]	0.5	1.5

T-1440

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.

[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100

[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100

[d] Add figures for total energy consumption of control device

[e] Number is rough estimate

[f] Low excess air operation could lower energy impact

TABLE 5-4. ENERGY CONSUMPTION DUE TO NO_x CONTROL TECHNIQUES FOR DISTILLATE OIL-FIRED BOILERS

System					Energy Consumption		
Standard Boiler							
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10^6 Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Firetube	4.4 (15)	No Control Device SIP	--	--	--	--	--
		Moderate	--	--	--	--	--
		Low Excess Air Intermediate	10	Oil	-0.2 (-0.075)	-0.5	-0.5
		Flue Gas Recirculation Stringent	40	Oil Electric	0.02 (0.075) 0.011 (0.04) } d	0.50 0.25 } d	0.5 0.25 } d
		Low NO_x Burners Stringent	40	Oil, Electric	None expected[e,f]	--	--
Watertube Without Air Preheater	29 (100)	No Control Device SIP	--	--	--	--	--
		Intermediate	--	--	--	--	--
		Flue Gas Recirculation Stringent	15	Oil Electric or Steam	0.14 (0.5) 0.07 (0.25) } d	0.5 0.25 } d	0.5 0.25 } d

T-1441

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.

[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100

[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100

[d] Add figures for total energy consumption of control device

[e] Number is rough estimate

[f] Low excess air operation could lower energy impact

Continued

TABLE 5-4. Continued

System					Energy Consumption		
Standard Boiler							
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10^6 Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Watertube Without Air Preheater (continued)	29 (100)	Low NO_x Burners Stringent	15	Electric, Oil	None expected[e,f]	--	--
		Low Excess Air and Overfire or Sidefire Air Stringent	15	Oil Electric or Steam	0.14 (0.5) 0.03 (0.1) } d	0.5 0.1 } d	0.5 0.1 } d
Watertube With Air Preheater	29 (100)	No Control Device SIP	--	--	--	--	--
		Low Excess Air Moderate	5	Oil	-0.07 (-0.25)	-0.25	-0.25
		Reduced Air Preheat Intermediate	30	Oil	0.44 (1.5)[f]	1.5	1.5
		Flue Gas Recirculation Intermediate	30	Oil Electric or Steam	0.14 (0.5) 0.07 (0.25)	0.5 0.25) } d	0.5 0.25 } d
		Low NO_x Burners Intermediate	30	Electric, Oil	0.07 (0.25)[e,f]	0.25	0.25

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.

T-1441

[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100

[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100

[d] Add figures for total energy consumption of control device

[e] Number is rough estimate

[f] Low excess air operation could lower energy impact

Continued

TABLE 5-4. Continued

System					Energy Consumption		
Standard Boiler							
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10^6 Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Watertube With Air Preheater (continued)	29 (100)	Low Excess Air and Overfire or Side-fire Air Intermediate	30	Oil Electric or Steam	0.14 (0.5) 0.03 (0.1) [d]	0.5 0.1 [d]	0.5 0.1 [d]
		Reduced Air Preheat and Flue Gas Recirculation Stringent	55	Oil Electric	0.6 (2.0) 0.07 (0.25) [d]	2.0 0.25 [d]	2.0 0.25 [d]
		Reduced Air Preheat and Low NO_x Burners Stringent	55	Oil Steam or Electric	0.44 (1.5)[f] 0.07 (0.25)[e]	1.5 0.25	1.5 0.25
Watertube With Air Preheater	44 (150)	No Control Device SIP	--	--	--	--	--
		Low Excess Air Moderate	5	Oil	-0.1 (-0.4)	-0.25	-0.25
		Reduced Air Preheat Intermediate	30	Oil	0.7 (2.2)[f]	1.5	1.5

T-1439

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.

[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100

[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100

[d] Add figures for total energy consumption of control device

[e] Number is rough estimate

[f] Low excess air operation could lower energy impact

Continued

TABLE 5-4. Concluded

System					Energy Consumption		
Standard Boiler							
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10^6 Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Watertube with Air Preheater (continued)	44 (150)	Flue Gas Recirculation Intermediate	30	Oil Electric or Steam	0.22 (0.75) 0.1 (0.4)	0.5 0.25) } d	0.5 0.25 } d
		Low NO_x Burners Intermediate	30	Electric, Oil	0.1 (0.4)[e,f]	0.25	0.25
		Low Excess Air and Overfire or Side-fire Air Intermediate	30	Oil Electric or Steam	0.22 (0.75) 0.04 (0.15) } d	0.5 0.1 } d	0.5 0.1 } d
		Reduced Air Pre-heat and Flue Gas Recirculation Stringent	55	Oil Electric	0.9 (3.0) 0.1 (0.4) } d	2.0 0.25 } d	2.0 0.25 } d
		Reduced Air Pre-heat and Low NO_x Burners Stringent	55	Oil Steam or Electric	0.44 (1.5)[f] 0.1 (0.4)[e]	1.5 0.25	1.5 0.25

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.

[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100

[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100

[d] Add figures for total energy consumption of control device

[e] Number is rough estimate

[f] Low excess air operation could lower energy impact

T-1439

could be used to reach stringent control levels. Low NO_x burners will probably only have a small energy impact. Ammonia injection is also only in the development stage and will probably have a small energy impact of about 0.5 percent.

Firetube boilers firing distillate oil need no controls to reach SIP (129 ng/J) or moderate (86 ng/J) control levels. Low excess air operation can be used to reach intermediate control levels (65 ng/J), with a fuel savings of about 0.5 percent. Stringent control levels (43 ng/J) can be reached by using either flue gas recirculation or low NO_x burners. Flue gas recirculation tests showed small thermal efficiency changes in most cases, but some tests did show losses up to 1 percent. A 0.5 percent loss is assumed and an additional fan power requirement of 0.25 percent of boiler heat input could be required.

Watertube boilers equipped with air preheaters firing distillate oil emit more NO_x than those units without preheaters. Economizers can be used to reclaim sensible heat from the flue gas without increasing NO_x emissions, as discussed in Section 3. Thus economizers should be used instead of air preheaters whenever possible. Watertube boilers without air preheaters need no controls to reach SIP or intermediate control levels. Flue gas recirculation, low NO_x burners, or staged combustion can be used to reach stringent control levels. The energy impacts of FGR, LNB, and staged combustion discussed above apply here also.

Watertube boilers equipped with air preheaters firing distillate oil need no controls to meet SIP levels. To meet moderate control levels, LEA could save about 0.25 percent in energy use. Reduced air preheat, FGR, LNB, or staged combustion could be used to reach intermediate control levels. Except for reduced air preheat, the energy impact of these controls have already been described. Reduced air preheat could lower efficiency by 1.5 percent, which would offset the efficiency gained by installing the air preheater. To meet stringent control levels, RAP and FGR or RAP and LNB could be used. Unless LEA or addition of an economizer is used with these two methods to lower the energy impact, they will use a large amount of energy. Reduced air preheat and flue gas recirculation could decrease boiler efficiency by 2 percent and increase fan power use by 0.25 percent. Reduced air preheat and low NO_x burners might increase fuel use 1.5 percent and require more fan power. Again, the efficiency gained by using the air preheater is lost, showing the advantage of an economizer instead of an air preheater.

5.3.2 Retrofitted Facilities

Retrofitted units have about the same energy impact as new units. Since staged combustion technique efficiency depends on air port location, it might not be possible when retrofitting to put the OFA or SFA ports in the optimal location. Since low NO_x burners change the flame shape, it might not be possible to retrofit these burners. Also, a new boiler could be designed to operate under a lower excess air level than an existing unit, especially, since burners have been developed that allow lower excess air operation (Reference 5-18).

5.4 ENERGY IMPACT OF CONTROLS FOR GAS-FIRED BOILERS

Data for the energy impact of combustion modifications for controlling NO_x emissions from natural gas-fired boilers were collected by KVB and Ultrasystems (References 5-7, 5-8, 5-9, and 5-14 through 5-17). Again, these were short term tests and the condition of the boiler was not always documented. Table 5-5 summarizes the energy impact on gas-fired industrial boilers. In all cases, LEA operation is recommended to minimize energy consumption.

5.4.1 New Facilities

A gas-fired firetube boiler should require no controls to meet SIP (86 ng/J) or stringent (43 ng/J) control levels. Again as in the oil-fired case, an economizer is recommended and for the same reasons: an economizer can save energy without increasing NO_x emissions. Watertube boilers without air preheaters need no controls to meet SIP or intermediate (65 ng/J) control levels. To meet stringent control levels, LEA could be used which would give about a 0.5 percent fuel savings.

For watertube boilers with air preheaters, controls are needed to meet SIP or moderate control levels. The recommended methods are RAP, FGR, staged combustion, and LNB. The energy impact of these controls have already been described. Fuel losses due to these techniques could be 2.0 percent for RAP, 0.5 percent for FGR, 0.5 percent for staged combustion, and negligible for LNB if they work as planned. It should be reiterated that low NO_x burners are in the development stage. The fuel loss for FGR and staged combustion would be less if the boiler is designed for and operated mainly on one type of fuel. As explained earlier, the

TABLE 5-5. ENERGY CONSUMPTION DUE TO NO_x CONTROL TECHNIQUES FOR NATURAL GAS-FIRED BOILERS

System					Energy Consumption		
Standard Boiler							
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10^6 Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Firetube	4.4 (15)	No Control Device					
		SIP	--	--	--	--	--
		Stringent	--	--	--	--	--
Watertube Without Air Preheater	29 (100)	No Control Device					
		SIP	--	--	--	--	--
		Intermediate	--	--	--	--	--
		Low Excess Air					
		Stringent	5	Gas	-0.14 (-0.5)	-0.5	-0.5
Watertube With Air Preheater	29 (100)	Reduced Air Preheat					
		SIP	25	Gas	0.6 (2.0)[f]	2.0	--
		Moderate	25				
		Flue Gas Recirculation					
		SIP	25	Gas	0.14 (0.5) } d,f	0.5 } d	--
		Moderate	25	Electric or Steam	0.07 (0.25) }	0.25 }	
		Low Excess Air and Overfire or Sidefire Air					
		SIP	25	Gas	0.14 (0.5) } d	0.5 } d	--
		Moderate	25	Electric or Steam	0.03 (0.1) }	0.1 }	--

T-1442

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.

[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100

[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100

[d] Add figures for total energy consumption of control device

[e] Number is a rough estimate

[f] Low excess air operation could lower energy impact

TABLE 5-5. Continued

System					Energy Consumption		
Standard Boiler							
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10^6 Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Watertube With Air Preheater (continued)	29 (100)	Low NO_x Burners SIP Moderate	 25 25	Gas, Electric	0.07 (0.25)[e,f]	0.25	--
		Reduced Air Preheat and Overfire or Sidefire Air Intermediate	40	Gas Electric or Steam	0.7 (2.5) 0.03 (0.1) } d,f	2.5 0.1 } d	2.0 --
		Reduced Air Preheat and Flue Gas Recirculation Stringent	60	Gas Electric	0.7 (2.5) 0.07 (0.25) } d,f	2.5 0.25 } d	2.0 0.15 } d
		Reduced Air Preheat and Low NO_x Burners Stringent	60	Gas Electric or Steam	0.6 (2.0)[f] 0.07 (0.25)	2.0 0.25	1.5 --
		Reduced Air Preheat and Ammonia Injection Stringent	60	Gas Electric	0.6 (2.0)[f] 0.14 (0.5)	2.0 0.5	1.5 --

T-1442

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.

[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100

[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100

[d] Add figures for total energy consumption of control device

[e] Number is a rough estimate

[f] Low excess air operation could lower energy impact

Continued

TABLE 5-5. Continued

System					Energy Consumption		
Standard Boiler							
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10^6 Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Watertube With Air Preheater	44 (150)	Reduced Air Preheat SIP Moderate	30 30	Gas	0.9 (3.0)[f]	2.0	--
		Flue Gas Recirculation SIP Moderate	30 30	Gas Electric or Steam	0.2 (0.8) 0.1 (0.4) } [d,f]	0.5 0.25 } [d]	--
		Low NO_x Burners SIP Moderate	30 30	Gas, Electric	0.01 (0.4)[e,f]	0.25	--
		Reduced Air Preheat and Overfire or Sidefire Air Intermediate	45	Gas Electric or Steam	0.1 (3.8) 0.04 (0.15) } [d,f]	2.5 0.1 } [d]	2.0 --
		Reduced Air Preheat and Flue Gas Recirculation Stringent	65	Gas Electric	1.1 (3.8) 0.1 (0.4) } [d,f]	2.5 0.25 } [d]	2.0 0.15 } [d]

T-1442

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.

[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100

[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100

[d] Add figures for total energy consumption of control device

[e] Number is a rough estimate

[f] Low excess air operation could lower energy impact

Continued

TABLE 5-5. Concluded

System					Energy Consumption		
Standard Boiler							
Type	Heat Input MW (10^6 Btu/hr)	Type and Level of Control[a]	Control Effectiveness Percent	Energy Types	Energy Consumed by Control Device MW (10^6 Btu/hr)	Percent Increase[b] in Energy Use Over Uncontrolled Boiler	Percent Change[c] in Energy Use Over SIP Controlled Boiler
Watertube With Air Preheater (continued)	44 (150)	Reduced Air Preheat and Low NO_x Burners Stringent	65	Gas Electric or Steam	0.6 (2.0)[f] 0.1 (0.4)[e,f]	2.0 0.25	1.5 --
		Reduced Air Preheat and Ammonia Injection Stringent	65	Gas Electric	0.6 (2.0)[f] 0.2 (0.8)	2.0 0.5	1.5 --

[a] Control levels moderate, intermediate, and stringent are discussed in Section 3. State Implementation Plan (SIP) control levels are given in Table 5-1.

T-1442

[b] (Energy consumed by control device, MW) ÷ (Standard boiler heat input, MW) X 100

[c] (Energy consumed by control device, MW - Energy consumed by SIP control device, MW) ÷ (Standard boiler heat input, MW + energy consumed by SIP control device, MW) X 100

[d] Add figures for total energy consumption of control device

[e] Number is a rough estimate

[f] Low excess air operation could lower energy impact

optimal air port location is fuel dependent and if only one type of fuel is burned, it would be easier to optimize the location. Air preheaters give about a 2 percent gain in efficiency, so the boiler is still more efficient in some cases, even with FGR or SCA operation, than a boiler with no air preheater. In other works, FGR or SCA may be more efficient than RAP on a boiler with an air preheater. Also FGR could require additional fan power equal to 0.25 percent of boiler heat input and staged combustion 0.1 percent; LNB may also require more fan power. For intermediate control, RAP plus OFA/SFA could be used. Using these techniques might increase fuel use by 2.5 percent and fan use by 0.1 percent of boiler heat input over an uncontrolled boiler. The methods that reach stringent control levels could also be used to achieve intermediate control levels.

To achieve stringent control levels, RAP plus FGR, RAP plus LNB, or RAP plus NH_3 injection could be used. As already discussed both LNB and NH_3 injection are in the development stage and only predicted energy impacts rather than tested ones can be given. Reduced air preheat and flue gas recirculation could increase fuel usage by 2.5 percent and fan power by 0.25 percent of boiler heat input. Reduced air preheat plus LNB might increase fuel consumption by 2 percent and slightly affect fan power usage. Reduced air preheat plus ammonia injection could increase fuel usage by about 2.5 percent.

5.4.2 Retrofitted Facilities

Energy impacts on retrofitted units would be about the same as new ones. Since the thermal efficiency of staged combustion depends on port location, it might not be possible to locate the air ports in the optimal location on a retrofit. For both staged combustion and FGR, the boiler might not have the proper windbox design to give the least pressure drop. A new boiler could be designed to operate at a lower excess air level than an existing one. Because of flame shape changes, it might not be possible to retrofit the most efficient low NO_x burner.

5.5 SUMMARY

Of the control methods just described, LEA is the most fuel efficient. Low excess air should be used with most control methods to increase efficiency and reduce NO_x emissions. Staged combustion air ports can be located so that thermal efficiency is not decreased if they are used with LEA and only one type of fuel is burned. For boilers that burn several fuels, several air ports would be needed and these ports may not always be in just the right location. Except for increased fan power use, it might be possible to design boilers so that FGR would not decrease thermal efficiency significantly. In some tests this was not always the case. Low NO_x burners should not decrease thermal efficiency and might even allow lower excess air operation which could increase thermal efficiency. Low NO_x burners are the most promising new technology. Ignoring NH_3 and carrier gas, ammonia injection appears to have only a minor energy impact though for raw material consumption, operational, and environmental reasons it might not be desirable. For new distillate oil- and gas-fired boilers, economizers are recommended over air preheaters as energy saving devices.

In summary, combustion modification NO_x controls for new industrial boilers should only have a minor energy inpact. In fact, with proper boiler design and control implementation, it might even be possible in some cases to significantly lower NO_x emissions and use less energy.

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SECTION 6

ENVIRONMENTAL IMPACTS OF CANDIDATES FOR BEST EMISSION CONTROL SYSTEMS

Modification of the combustion process for NO_x control can alter the emission rates of other pollutants. These changes, referred to as incremental emissions, could lead to adverse environmental effects. Therefore, a key consideration of all NO_x control development programs must be the effects on emission levels of the criteria pollutants: carbon monoxide (CO), unburned hydrocarbons (UHC), particulate, and sulfur oxides (SO_x), and the SO_2/SO_3 ratio. Also of concern in recent control development programs are the noncriteria pollutants, trace metals and organics.

This section presents the expected effect of combustion modification NO_x controls on the criteria and noncriteria pollutants. These postulations are further supported by a review of the possible formation mechanisms for each pollutant. However, data are insufficient to completely describe the effect of the NO_x control and the resulting incremental emissions. The data that are available are presented as a function of boiler and fuel type.

6.1 IDENTIFICATION OF THE MAJOR ENVIRONMENTAL CONCERNS

The candidate best NO_x control system for each fuel category was presented in Tables 3-7, 3-8, 3-10, 3-11, and 3-12. Table 6-1 presents the expected effect each modification will have on incremental emissions. A review of Table 6-1 shows that:

- Increased CO and vapor phase hydrocarbon emissions are of major concern only when excess air levels are lowered
- Sulfate emission levels are expected to decrease or remain unchanged with all controls except staged combustion and

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TABLE 6-1. POSTULATED EFFECT OF COMBUSTION MODIFICATIONS ON INCREMENTAL EMISSIONS FROM INDUSTRIAL BOILERS.

T-169

Combustion Modification	Resulting Combustion Conditions	CO	Vapor Phase HC	Sulfate	Organics
Low excess air	Reduced local O_2 concentration; decreased gas velocities; increased furnace residence time	Increased	Increased	Decreased overall because of lowered O_2 availability	Possibly increased
Staged combustion	Reduced local O_2 concentration; reduced peak flame temperature; increased convection zone temperature; delayed flame zone mixing	Possibly increased	Possibly increased	Possibly decreased because of decreased convection zone catalysis (less volatile metal redistribution)	Possibly increased
Flue gas recirculation	Reduced local O_2 concentration; reduced peak flame temperature; reduced furnace residence time; increased gas velocities; more turbulent flame; increased convective zone temperature	Possibly increased	Possibly increased	Possibly decreased	Possibly increased
Reduced air preheat	Reduced peak flame temperature; decreased gas velocities; increased furnace residence times; increased local O_2 concentration	No effect	No effect	Possibly decreased	Possibly increased
Ammonia injection	Increased local NH_3 concentration	No effect	No effect	Possibly increased through near plume solution catalysis	Decreased with decreased particle emissions; no effect otherwise
Low NO_x burners	Delayed fuel-air mixing; off-stoichiometric combustion	Possibly increased	Possibly increased	Possibly decreased because of less potential for SO_2 oxidation	Possibly increased due to greater carbonaceous particle formation

Continued

TABLE 6-1. (Concluded)

Combustion Modification	Particulate		Trace Metals	
	Size Distribution	Mass Emissions	Segregating	Nonsegregating
Low excess air	Possible trend to larger sizes	Possibly decreased because of increased bottom and ash fallout and internal deposition	Unknown effect: possible increase due to increased volatility but possible decrease with internal deposition	Possibly reduced because of reduced mineral particle emissions and internal particle deposition
Staged combustion	Possible trend to larger sizes	Unknown effect: possible increase due to soot formation; possible decrease due to larger particles and convection zone depositon and slagging	Possibly decreased because of decreased repartitioning to small particles	Possibly reduced due to larger particles (more carbon) and convection zone slagging
Flue gas recirculation	Probably no effect	Possibly increased due to increased velocities and possibility of soot formation	Possibly decreased because of decreased repartitioning to small particles	Possibly increased with increased particle emissions
Reduced air preheat	Probably no effect	Possibly increased due to less bottom slagging	Possibly reduced because of less concentration in small particles	Possibly increased with increased particle emissions
Reduced load	Probably no effect	Probably no net effect	Possibly reduced because of less concentration in small particles	Probably no effect
Ammonia injection	Trend to smaller particles (NH_4HSO_4 aerosol)	Possibly decreased with ESPs because of conditioning; increased otherwise	Possibly increased because larger fraction of small particles	Decreased with decreased particle emissions; no effect otherwise
Low NO_x burners	Trend to larger particles	Possibly increased because of greater soot formation	Possibly decreased because of overall trend to larger particles more easily controlled	Possibly decreased because larger particles more easily controlled

ammonia injection (which alters the form of SO_3 to NH_3HSO_4)

- Changes in emitted particle size distribution are expected only when operating with low excess air, staged combustion or low NO_x burners. In these instances the production of larger particles is expected.
- Increased particulate mass emissions are of potential concern when flue gas recirculation, staged combustion, or low NO_x burners are used
- Condensible organic emissions are likely to increase with all combustion NO_x controls except ammonia injection
- Decreased segregating trace metal emissions are possible when using staged combustion, flue gas recirculation, or ammonia injection. Segregating species are those that are partitioned to various particle sizes.
- Nonsegregating trace metal emissions are only of potential concern when implementing flue gas recirculation and reduced air preheat

The following subsection discusses the formation mechanism for each pollutant as a function of the combustion conditions.

Obviously care must be taken when quantifying impacts of NO_x controls. A careful balance between reduced NO_x and increased incremental emissions must be maintained to minimize the total impact on ambient environmental goals.

6.2 FORMATION MECHANISMS OF MAJOR POLLUTANTS

Since incremental emissions are sensitive to the same combustion conditions as NO_x, an understanding of the formation mechanisms of these incremental pollutants will permit a better appreciation of how NO_x control conditions affect these combustion generated pollutants. Such knowledge can aid in the interpretation of the limited field test data available and provide informed speculation on how NO_x controls act. Subsection 6.2.1 reviews the formation mechanism of the criteria pollutants: carbon monoxide, unburned hydrocarbons, particulate, and sulfur oxides. (Nitrogen oxides formation has already been discussed in Section 2.) Subsection 6.2.2 discusses the formation mechanisms of the noncriteria pollutants: trace metals and organics.

6.2.1 Criteria Pollutants - Formation Mechanisms

Carbon Monoxides

The presence of CO in the exhaust gases of combustion systems results principally from incomplete fuel combustion. Several conditions can result in incomplete combustion. These include:

- Insufficient oxygen availability
- Poor fuel/air mixing
- Cold wall flame quenching
- Reduced combustion temperature
- Decreased combustion gas residence time
- Load reduction (reduced efficiency)

Since various combustion modifications for NO_x reduction can produce one or more of the above conditions, the possibility of increased CO emissions is a concern for environmental, energy and operational reasons. Flue gas CO emission concentrations in excess of 2000 ppm can severely damage equipment from explosions in flue gas exit passages (Reference 6-1).

Unburned Hydrocarbons

Unburned hydrocarbon emissions can include essentially all vapor phase organic compounds emitted from a combustion source. These are primarily emissions of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in the vapor phase at flue gas temperatures. These emissions include all alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e.g., benzene, toluene, xylene, ethyl benzene, etc.) (References 6-2 and 6-3). Condensed phase organic compounds are presently noncriteria pollutants and are discussed in Section 6.3.

Like CO, UHC occur due to incomplete combustion. Therefore, any combustion modification which reduces the combustion efficiency will most likely increase the concentrations of vapor phase hydrocarbons. These pollutants are of environmental concern because of their role in the atmospheric reactions which lead to photochemical smog (Reference 6-1).

Total Particulate

Gas-fired combustion equipment produces negligible amounts of particulate matter. The quantity of emissions increases when distillate oil and residual oil are used and the greatest quantity is emitted when coal is the primary fuel (Reference 6-4).

Particulate emissions from oil-fired units can be composed of soot (condensed organic matter) and ash (incombustible mineral matter). Coal particulate emissions are largely ash, and occasionally contain some unburned carbonaceous residue (Reference 6-1). The composition of the particulate generated in the combustor can affect mass emissions. This is due primarily to the relationship between composition and particle size, and the particulate control device employed for particle removal. In addition, some trace element emissions depend on the particle size distribution. Finally, polycyclic organic matter (POM) emissions from combustion sources occur largely as solid phase carbonaceous residue. High particulate emissions, especially from coal-fired boilers, may increase the possibility of high POM emissions (Reference 6-1). (The formation mechanisms and emissions of trace elements and POM are discussed in later sections.)

The formation of particulates in a combustion source is closely related to combustion aerodynamics, the mechanisms of fuel/air mixing, and the effects of these factors on combustion gas temperature-time history. The optimum conditions for reducing particulate formation (intense, high temperature flames as produced in high turbulence and rapid fuel/air mixing) are not the conditions for suppressing NO_x formation. Therefore, most attempts to design low-NO_x combustors have been compromised by the need to limit the formation of particulates (Reference 6-1).

Particulate emissions are subdivided into expected particle size distribution and particulate mass emissions. When NO_x controls are applied to reduce combustion efficiency, condensible organic matter (soot) increases. If the combustion modification results in a reducing atmosphere rather than an oxidizing atmosphere, ash emissions may decrease due to increased slag formation and internal deposition of ash ("bottom ash").

Particle size distribution can affect the emissions of trace metals. Some trace metals segregate to the smaller particle sizes. If combustion modifications reduce particle sizes, segregating trace metals emissions will increase. Since small particulate remains suspended for larger periods of time, it can penetrate the body's respiratory system more easily, and remain in the lungs for longer periods of time.

Therefore, greater adverse health effects are possible. The more complete the combustion, the smaller the particle size distribution. Therefore, loss of combustion efficiency can result in increased mass emissions from the boiler and increased particle size (Reference 6-1). Larger particles are more easily removed by pollution control devices. Boilers equipped with these devices may reduce mass emissions from the stack when combustion efficiency is reduced.

Sulfates

Ambient sulfate levels are of increasing concern in regions with large numbers of combustion sources firing sulfur-bearing coal and oil. Although the direct health effects of high ambient sulfate levels are currently unclear (Reference 6-5), high sulfate aerosol concentrations decrease visibility and aggravate acid precipitation.

Ambient sulfates are generally comprised of directly emitted sulfates (primary sulfates) and those derived from the atmospheric oxidation of sulfur dioxide, SO_2, (secondary sulfates). Sulfur dioxide is emitted when sulfur is contained in the fuel. Up to 98 percent of all sulfur entering the boiler may be discharged as SO_2. The primary concern for incremental emissions, then, is to control the ratio of primary sulfate to SO_2 (SO_4/SO_2). The sulfate present may exist as either sulfuric acid (H_2SO_4) or as metal or ammonium sulfates.

The precise mechanisms for the formation of sulfates are not completely understood. However, two processes contribute to final flue gas sulfate levels. The first is homogeneous SO_2 oxidation in the flame through the reaction:

$$SO_2 + O + M = SO_3 + M \qquad (6\text{-}1)$$

where M is a third body molecule. Although SO_2 is the thermodynamically favored product at high temperatures, it is currently thought that some SO_3 is formed through Equation (6-1). Subsequent rapid gas quenching then freezes the system into a nonequilibrium state. Any SO_3 formed through this reaction will, at reduced temperatures, combine with available water vapor to form sulfuric acid. This sulfuric acid will then adsorb onto available particulate matter or, in the absence of sufficient particulate matter, condense as an acid mist.

The second important sulfate formation mechanism is catalyzed heterogeneous SO_2 oxidation in postcombustion regions by flue gas particulate and internal boiler deposits. Several potential oxidation catalysts exist in suspended and deposited flue gas particulate, including vanadium, nickel, iron, manganese oxides, and carbon (soot).

Based on the above, it is possible to speculate how NO_x controls might affect primary sulfate production. Reduced oxygen availability should definitely decrease primary sulfate emissions. Thus, NO_x controls which decrease local oxygen availability should lower sulfate emission levels. It is difficult to identify the effects of combustor temperature time history on sulfate production. This is because not much is known about in situ catalytic mechanisms and their relative importance to homogeneous SO_2 oxidation. Since trace metals present in the gas stream catalytically oxidize SO_2 to SO_3, combustion conditions which facilitate volatilization-condensation and partitioning of these metals, such as high peak flame temperatures, should promote SO_2 conversion. Conversely, combustion controls which lower peak flame temperature should decrease sulfate production.

6.2.2 Noncriteria Pollutants -- Formation Mechanisms

Organics

Organics are those species not included in the criteria pollutant class of unburned vapor phase hydrocarbons. The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known variously as polycyclic organic matter (POM) or polynuclear aromatic hydrocarbons (PNA or PAH). The following discussion treats POM emissions from stationary combustion sources and the effects of NO_x controls on these emissions.

Although polycyclic organic matter can conceivably be formed in the combustion of any hydrocarbon fuel, it is considered more of a problem when associated with soot (carbonaceous particulate) emissions from coal- and oil-fired combustion equipment. Polycyclic organic matter are especially prevalent in the emissions from coal burning, because a large fraction of the volatile matter in coal (coal tar) preexists as POM.

Although the formation of POM in flames is complex and variable, it is possible to form a relatively clear picture of the overall reaction.

In a reducing atmosphere at temperatures around 2,000K (conditions common in the center of flames), radical species of the form, HC=CH and RCH=CH, can rapidly combine and form large polynuclear aromatic molecules through radical chain propagation (References 6-3, 6-6). As combustion gas cools and chain propagation is quenched, a variety of POM species can remain when combustion is incomplete. Upon further cooling, these species condense and are emitted largely as soot or high carbon content particulate.

POM emissions have significant environmental impact because several species are highly carcinogenic (Reference 6-3). The fact that they generally exist as fine particulate makes them an even more serious health hazard.

It is important to again note that although POM formation is possible during methane combustion, the formation of these large aromatic molecules is facilitated by the presence of higher molecular weight radicals. Thus, POM production is of only minor concern in gas-fired systems, of some concern in oil-fired systems, and of greatest concern in coal-fired equipment. Whatever the combustion source, POM emissions should increase under conditions of poor combustion efficiency. Since NO_x combustion controls can lead to inefficient combustion and soot formation if not carefully applied (especially low excess air and staged combustion), implementation of these controls can lead to increased POM formation.

A few comments are in order here concerning an extremely toxic subclass of polynuclear aromatic hydrocarbons, the polychlorinated and polybrominated biphenyls (PCBs and PBBs). A theoretical assessment of PCB formation in combustion sources (Reference 6-7) concluded that, although PCB formation is thermodynamically possible during coal and residual oil (fuels which contain some chlorine) combustion, it is unlikely due to short reaction residence times and low chlorine concentrations. If PCBs are formed, they would be expected to occur under conditions which promote POM emissions. However, PCBs have never been verified in conventional combustion source emissions.

Trace Elements

Emissions of trace metals are a concern for combustion sources firing coal and residual oil. They are a lesser problem in sources firing distillate fuels since trace metal concentrations in distillate oils are generally much lower than those in residual oils. Trace metals from stationary sources are emitted to the atmosphere with the flue gas either as a vapor or condensed on particulate. The quantity of any given metal emitted, in general, depends on:

- Its concentration in the fuel
- The combustion conditions in the boiler
- The type of particulate control device used, and its collection efficiency as a function of particle size
- The physical and chemical properties of the element itself

It has become widely recognized that some trace metals concentrate in certain waste particle streams from a boiler (bottom ash, collector ash, flue gas particulate), while others do not (References 6-8 through 6-14). The most logical explanation for this segregation involves a volatilization-condensation mechanism (Reference 6-8). Certain metals have boiling points sufficiently high that they are not volatilized in the combustion zone. Instead, they form a melt of relatively uniform concentration, which becomes both bottom ash or slag, and flyash. Thus, these elements, termed Class I, remain in a condensed phase throughout the boiler and show little partitioning with particle size. By contrast, other metals have boiling points below peak combustion temperatures, so they are volatilized in the combustion zone and do not become incorporated in the slag. As combustion gases cool by traveling through the boiler, these elements, termed Class II, either form condensation nuclei or condense onto other available solid surfaces (predominantly preexisting Class I ash particles). Since the available surface area to mass ratio increases as particle size decreases, these elements concentrate in small particles. Finally, metals such as Mercury (Hg) and to some extent Selenium (Se), remain vaporized through the stack and are emitted as flue gas vapor components. These are referred to as Class III metals.

By understanding trace metal partitioning and concentration in fine particulate, it is possible to postulate the effects of NO_x combustion controls on incremental trace metal emissions. Several NO_x controls for boilers reduce peak flame temperatures (staged combustion, flue gas recirculation, reduced air preheat, load reduction, and water injection). The volatilization-condensation theory predicts that if the combustion temperature is reduced, less Class II metals will initially volatilize, hence less will be available for subsequent condensation. Under these conditions (lowered flame temperature), it is expected that less Class II metal (the segregating trace metals) will be redistributed to small particulate. Therefore, in boilers with particulate controls, lowered volatile metal emissions should result due to improved particulate removal. Flue gas emissions of class I metals (the nonsegregating trace metals) should remain relatively unchanged.

Lowered local O_2 concentrations are also expected to affect segregating metal emissions from boilers with particle controls. Lowered O_2 availability decreases the possibility of volatile metal oxidation to less volatile oxides. Under these conditions Class II metals should remain in the vapor phase into the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, class I metals should be unaffected. This behavior is expected when low excess air is implemented. Other combustion NO_x controls which decrease local O_2 concentrations (Staged Combustion and flue gas recirculation) also reduce peak flame temperature. For these, the effect of lowered combustion temperature is expected to predominate.

The effect of NO_x combustion controls on segregating metal emissions from combustion sources without particle collection devices should be marginal at best. Particle redistribution will not affect mass emissions because all particulate produced is emitted from these sources. However, since trace metal condensation on internal boiler surfaces undoubtedly occurs, conditions which decrease the extent of Class II metal volatilization (lowered peak flame temperature) should cause a slight decrease in segregating metal emissions. Conversely, conditions which increase metal volatility (low local O_2 concentrations) should cause slight increases in volatile metal emissions (Reference 6-1).

6.3 ENVIRONMENTAL IMPACTS OF NO_x CONTROLS FOR COAL-FIRED BOILERS

Coal-fired industrial boilers have been grouped into four equipment categories as follows:

- Field erected, pulverized coal.
- Field erected, stoker, spreader stoker
- Field erected, stoker, chain grate stoker
- Packaged, stoker, underfeed stoker

The recommended NO_x control levels for the various fuels for industrial boilers were presented in Table 3-6. These recommendations, coupled with the NO_x control techniques discussed in Section II, provided the data for Tables 3-7 and 3-8, which showed the best control method to reach a given standard. However, the incremental impact of each suggested control must be known before the control is implemented on a widespread basis.

Table 6-2 presents incremental emission data from recently completed field test programs (References 6-15 and 6-19 through 6-21). Included in this test series were stoker type industrial boilers, as presented in Table 6-3. The information from these tables is presented graphically in Figures 6-1 and 6-2.

All tests used low excess air for NO_x control except test series H, which included one overfire air test and test N which included one high excess air test. In nearly all cases, CO emissions increased slightly, as predicted. Unburned vapor phase hydrocarbon emissions fluctuated between increases and decreases.

All comparative particulate tests show a decrease in particulate emissions following a particulate control device. Reduced excess air was expected to increase particle size. This would make the particles easier to collect in particulate control devices. Since all boilers in the comparative tests were equipped with dust control devices, it appears that the predicted effect is correct. Reduced excess air was expected to increase mass emissions of particulates.

The particle size distribution of the ash emitted from a boiler will also increase with low excess and overfire air NO_x control. This is due to a slight decrease in combustion efficiency. Table 6-4 presents test data collected downstream of a dust collection device during a recent field test program (Reference 6-16). Though other tests were conducted, these data were the only comparative test data identified. A clear shift to larger particle size is noted. These data, coupled with the results from Figures 6-1 and 6-2, further suggest improved dust removal device efficiency and reduced particulate mass emissions from the stack.

Data collected during a coal-fired boiler test program (Reference 6-16) are in accordance with the trace metal partitioning theory discussed in Section 6-3. Figure 6-3 illustrates the partitioning of low-volatility iron, moderately volatile cobalt, and highly volatile copper.

TABLE 6-2. INCREMENTAL EMISSIONS FROM PULVERIZED COAL-FIRED INDUSTRIAL BOILERS (References 6-15 and 6-20)

Boiler Test Series	System		NO_x Control (Excess O_2, %)	NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type		ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
A	116/145 (400)/(500)	Watertube Single Wall	Baseline (8.6)	216	--	CO	29	--
						UHC	--	--
						SO_3	--	--
						PART	1140	--
	133/145 (390)/(500)	Watertube Single Wall	Low Excess Air (8.1)	212	-4	CO	47	+18
						UHC	--	--
						SO_3	--	--
						PART	--	--
B	38/75 (129)/(260)	Watertube Single Wall	Baseline (7.4)	563	--	CO	0	--
						UHC	--	--
						SO_3	6	--
						PART	2288	--
	38/75 (130)/(260)	Watertube Single Wall	Low Excess Air (6.6)	529	-34	CO	0	0
						UHC	--	--
						SO_3	--	--
						PART	--	--
C	53/65 (180)/(220)	Watertube Tangential	Baseline (5.3)	234	--	CO	0	--
						UHC	4	--
						SO_3	5	--
						PART	511	--
	53/65 (180)/(220)	Watertube Tangential	Low Excess Air (4.5)	222	-12	CO	--	--
						UHC	1	-3
						SO_3	--	--
						PART	--	--

Continued T-1447

[a] No data available on noncriteria emissions

TABLE 6-2. Concluded

Boiler Test Series	System		NO$_x$ Control (Excess O$_2$, %)	NO$_x$ Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type		ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
D	76/93 (260)/(320)	Watertube Tangential	Baseline (5.8)	296	--	CO UHC SO$_3$ PART	0 2 9 834	-- -- -- --
	76/93 (261)/(320)	Watertube Tangential	Low Excess Air (4.8)	303	+7	CO UHC SO$_3$ PART	0 1 -- --	0 -1 -- --
E	38/67.2 (130)/(230)	Watertube Single Wall	Baseline (4.5)	201	--	CO UHC SO$_3$ PART	11 90 4.7 --	-- -- -- --
	38/67.2 (130)/(230)	Watertube Single Wall	Low Excess Air (3.4)	152	-49	CO UHC SO$_3$ PART	12 5.4 2.2 2895	+1 -3.6 -2.5 --
F	32.8/46.7 (112)/(160)	Watertube Single Wall	Baseline (5.1)	174	--	CO UHC SO$_3$ PART	23.2 10 21.7 1194	-- -- -- --
	33.1/46.7 (113)/(160)	Watertube Single Wall	Low Excess Air (3.4)	136	-38	CO UHC SO$_3$ PART	4.2 14 0 995	+19 +4 -21.7 -199

T-1447

[a] No data available on noncriteria emissions

TABLE 6-3. INCREMENTAL EMISSIONS FROM STOKER COAL-FIRED INDUSTRIAL BOILERS (References 6-15 and 6-20)

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
G	30/62 (103)/(210)	Watertube Chain Grate	Baseline (9.5)	100	--	CO UHC SO_3 PART	9 5 -- 176	-- -- -- --
	30/62 (100)/(210)	Watertube Chain Grate	Low Excess Air (9.0)	75	-25	CO UHC SO_3 PART	22 11 -- 161	+13 +6 -- -15
	30/62 (105)/(20)	Watertube Chain Grate	Low Excess Air (8.7)	77	-23	CO UHC SO_3 PART	20 4 -- --	+11 -2 -- --
H	24/36 (81)/(125)	Watertube Spreader Stoker	Baseline (6.2)	196	--	CO UHC SO_3 PART	0 -- 20 1320	-- -- -- --
	24/36 (81)/(125)	Watertube Spreader Stoker	Overfire Air (6.1)	145	-51	CO UHC SO_3 PART	18 -- -- --	+18 -- -- --
	24/36 (82)/(120)	Watertube Spreader Stoker	Low Excess Air (4.7)	142	-54	CO UHC SO_3 PART	8 -- -- 847	+8 -- -- -473

[a] No data available on noncriteria emissions

Continued

T-1446

TABLE 6-3. Continued

	System			NO_x Emissions		Criteria Emissions[a]		
Boiler Test Series	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
I	14/17 (48)/(60)	Watertube Underfeed Stoker	Baseline (6.6)	163	--	CO UHC SO_3 PART	0 -- 23 --	-- -- -- --
	13/17 (44)/(60)	Watertube Underfeed Stoker	Low Excess Air (4.9)	115	-48	CO UHC SO_3 PART	0 -- -- --	0 -- -- --
	13/17 (45)/(60)	Watertube Underfeed Stoker	Baseline (9.8)	137	--	CO UHC SO_3 PART	0 -- -- 1647	-- -- -- --
	13/17 (45)/(60)	Watertube Underfeed Stoker	Low Excess Air (7.0)	123	-14	CO UHC SO_3 PART	119 -- --	+119 -- --
J	32/39 (109)/(135)	Watertube Spreader Stoker	Baseline (7.0)	226	--	CO UHC SO_3 PART	10 5 15 1587	-- -- -- --
	33/39 (112)/(135)	Watertube Spreader Stoker	Low Excess Air (4.9)	205	-21	CO UHC SO_3 PART	47 2 --	+37 -3 --
K	12/15 (40)/(50)	Watertube Spreader Stoker	Baseline (8.0)	284	--	CO UHC SO_3 PART	9 2 15	-- -- --
	12/15 (40)/(50)	Watertube Spreader Stoker	Low Excess Air (5.8)	202	-82	CO UHC SO_3 PART	7 4 -- 279	-2 +2 -- -219

[a] No data available on noncriteria emissions

Continued

T-1446

TABLE 6-3. Continued

Boiler Test Series	System		NO_x Control (Excess O_2, %)	NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type		ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
L	18/22 (60)/(75)	Watertube Spreader Stoker	Baseline (7.8)	284	--	CO UHC SO_3 PART	34 2 28 140	-- -- -- --
	18/22 (62)/(75)	Watertube Spreader Stoker	Low Excess Air (5.9)	237	-47	CO UHC SO_3 PART	22 4 -- 123	-12 +2 -- +17
M	35/44 (119)/(150)	Watertube Spreader Stoker	Baseline (10.2)	338	--	CO UHC SO_3 PART	0 -- 36 1649	-- -- -- --
	36/44 (120)/(150)	Watertube Spreader	Low Excess Air (8.9)	228	-50	CO UHC SO_3 PART	0 -- -- --	0 -- -- --
N	47/67 (160)/(120)	Watertube Spreader Stoker	Baseline (10.8)	334	--	CO UHC SO_3 PART	0 -- 4 361	-- -- -- --
	44/67 (150)/(230)	Watertube Spreader Stoker	Low Excess Air (8.9)	220	-114	CO UHC SO_3 PART	0 -- -- --	0 -- -- --
	42/67 (143)/(230)	Watertube Spreader Stoker	High Excess Air (HEA) (12.6)	241	-93	CO UHC SO_3 PART	0 -- 13 317	0 -- +9 -44

[a] No data available on noncriteria emissions

Continued T-1446

TABLE 6-3. Continued

Boiler Test Series	System: Actual/Design Heat Input MW (10^6 Btu/hr)	System: Boiler Type	NO_x Control (Excess O_2, %)	NO_x Emissions: ng/J	NO_x Emissions: Incremental Change, ng/J	Criteria Emissions[a]: Pollutant	Criteria Emissions[a]: ng/J	Criteria Emissions[a]: Incremental Change, ng/J
P	17.6/29.3 (60)/(100)	Watertube Spreader Stoker	Baseline Montana Coal (10.9)	312	--	CO UHC SO_3 PART	205 -- 10 447	-- -- -- --
	17.6/29.3 (60)/(100)	Watertube Spreader Stoker	Low Excess Air Montana Coal (6.5)	206	-106	CO UHC SO_3 PART	17 -- -- 388	-188 -- -- --
	17.6/29.3 (60)/(100)	Watertube Spreader Stoker	Baseline Illinois Coal (10.0)	289	--	CO UHC SO_3 PART	18 -- 9 674	-- -- -- --
	17.6/29.3 (60)/(100)	Watertube Spreader Stoker	Low Excess Air Illinois Coal (7.8)	258	-31	CO UHC SO_3 PART	0 -- -- 455	-18 -- -- -219
Q	43.2/46.9 (83)/(160)	Watertube Spreader Stoker	Baseline Montana Coal (8.6)	326	--	CO UHC SO_3 PART	53 -- 14 --	-- -- -- --
	23.1/46.9 (79)/(160)	Watertube Spreader Stoker	Low Excess Air Montana Coal (7.7)	183	-53	CO UHC SO_3 PART	48 -- -- 5803	-5 -- -- --
	31.5/46.9 (107)/(160)	Watertube Spreader Stoker	Baseline Illinois Coal (8.6)	287	--	CO UHC SO_3 PART	17 -- -- --	-- -- -- --
	32.2/46.9 (110)/(160)	Watertube Spreader Stoker	Low Excess Air Illinois Coal (6.6)	241	-46	CO UHC SO_3 PART	33 -- -- 234	-84 -- -- --

[a] Cyclone outlet only

Continued

T-1446

TABLE 6-3. Concluded

Boiler Test Series	System		NO$_x$ Control (Excess O$_2$, %)	NO$_x$ Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type		ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
R	13.4/23.4 (45.7/(80)	Watertube Spreader Stoker	Baseline 2/3 Illinois, 1/3 Montana Coal (9.4)	207	--	CO	61	--
						UHC	--	--
						SO$_3$	133	--
						PART	1209	--
	13.4/23.4 (45.9/(80)	Watertube Spreader Stoker	Low Excess 2/3 Illinois, 1/3 Montana Coal (8.0)	239	+32	CO	33	-28
						UHC	--	--
						SO$_3$	44	-89
						PART	987	-222
S	5.0/13.2 (17.0/(45)	Watertube Vibrating Grate Stoker	Baseline Western Coal (9.8)	199	--	CO	18	--
						UHC	--	--
						SO$_3$	--	--
						PART	--	--
	5.0/13.2 (17.0/(45)	Watertube Vibrating Grate Stoker	Low Excess Western Coal (7.3)	152	-47	CO	8	-10
						UHC	--	--
						SO$_3$	--	--
						PART	--	--

[a] No data available on noncriteria emissions

T-1446

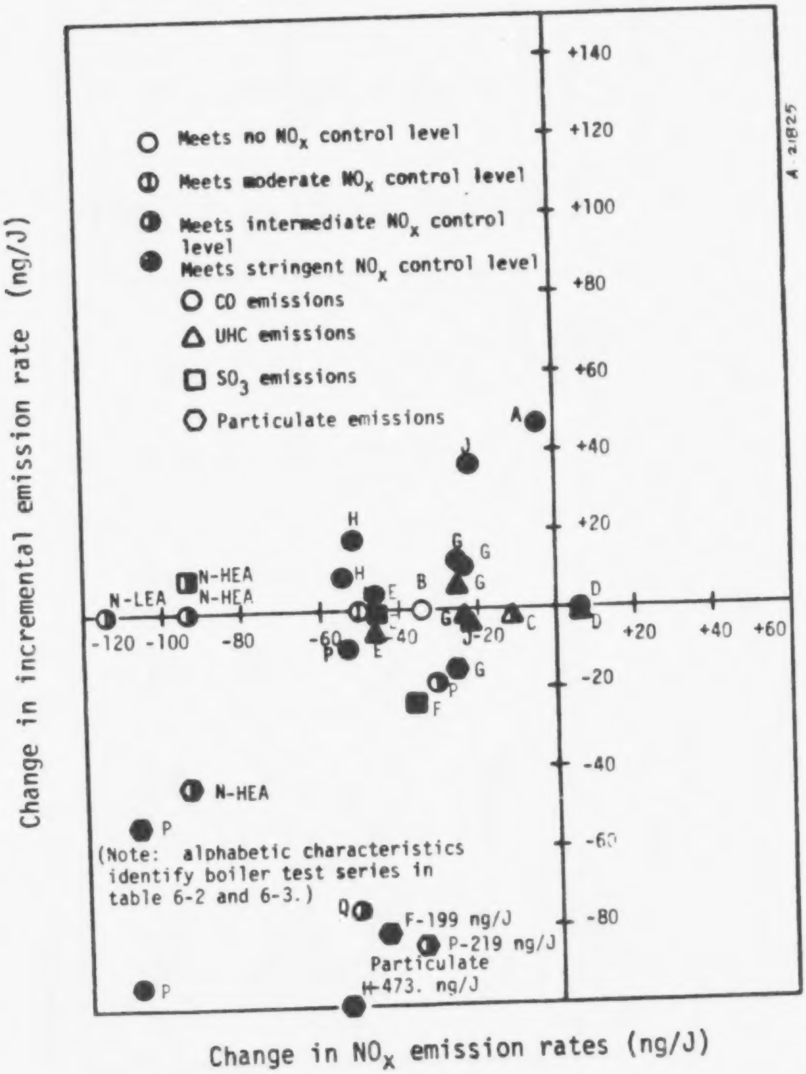


Figure 6-1. Change in incremental emissions from coal-fired industrial boilers >29 MW (100 x 10^6 Btu/hr).

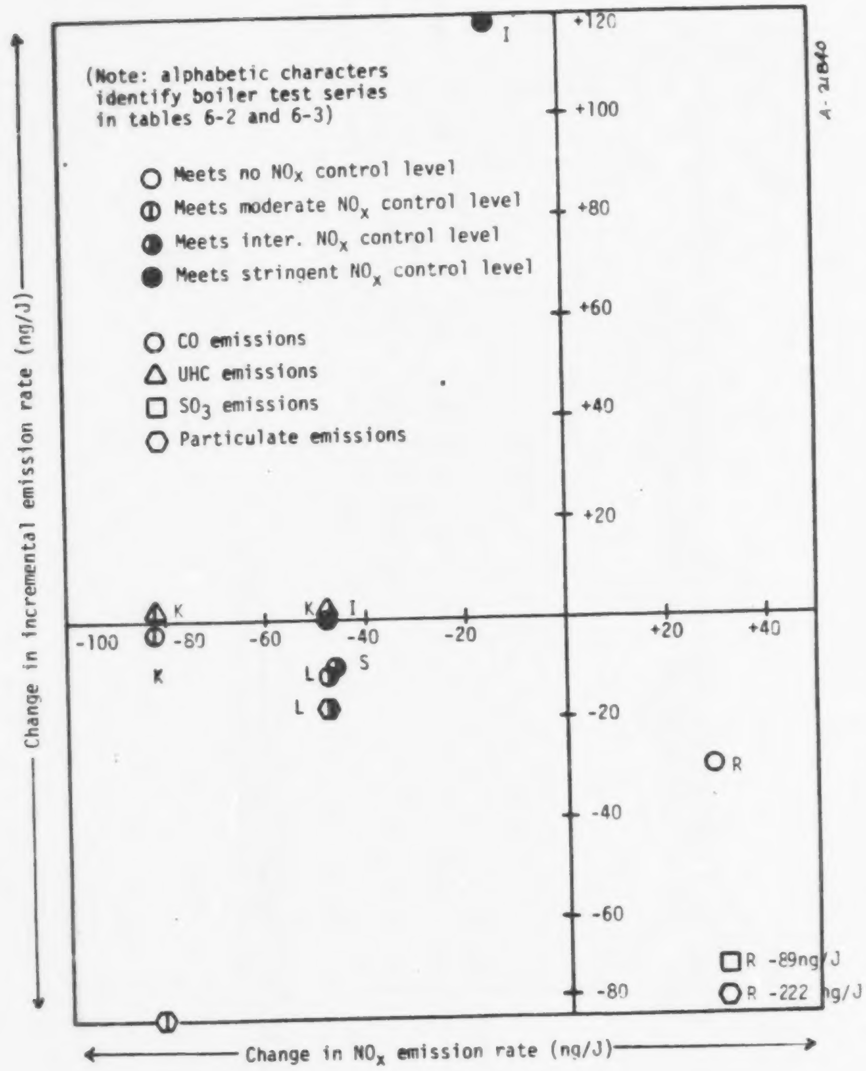


Figure 6-2. Change in incremental emissions from coal-fired industrial boilers <29 MW (100 x 10^6 Btu/hr).

TABLE 6-4. EFFECT OF OVERFIRE AIR NO_x CONTROL ON PARTICLE SIZE DISTRIBUTION[a] FOR A COAL-FIRED CHAIN GRATE STOKER (Reference 6-16)

						Actual D_{50} of Stage No.[b]						Cyclone, Stage and Filter Catch								
												Stage No.								
Fuel Type	Burner Type	Test Load GJ hr^{-1}	NO_x ng/J	Impact Flow cm^3 s^{-1}	D_{50} Cycl. µm	1 µm	2 µm	3 µm	4 µm	5 µm	Cyclone mg	1 mg	2 mg	3 mg	4 mg	5 mg	Filter mg	Total Catch mg	Comments
Coal	Grate	112	85.5	24.6	15.6	3.5	2.1	1.4	0.70	0.35	10.39	1.056	0.780	0.660	0.340	0.600	0.572	14.60	Baseline no soot
Coal	Grate	103	--	23.6	15.1	3.5	2.1	1.4	0.71	0.35	10.82	0.200	0.276	0.472	2.10	3.26	1.29	18.42	Low NO_x no soot

T-1451

[a] Particle size distribution determined by use of a Brink model "B' cascade impactor

[b] D_{50} identifies the size fraction in microns. Particulates with an aerodynamic diameter greater than the D_{50} cut point will be captured. Increasing stage number corresponds to decreasing particle size.

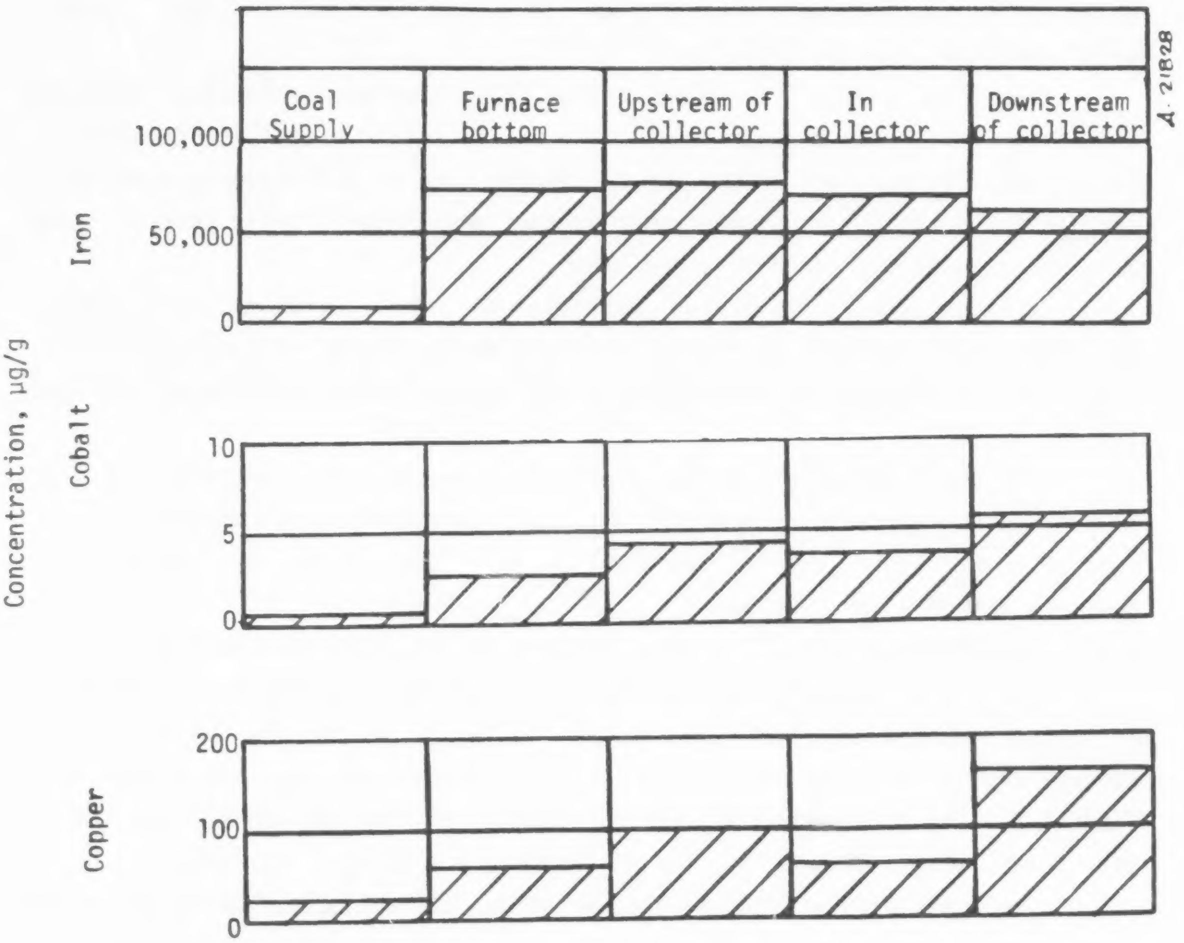


Figure 6-3. Partitioning of elements based on effluent location for a coal-fired industrial boiler (Reference 6-16).

Test data collected during the same test program (Reference 6-16) support the trace metal segregation theory as discussed in Section 6.3. As shown in Figure 6-4, the concentration of the volatile element antimony increased as the particle size decreased. The concentration of less volatile manganese remains relatively evenly distributed between particulate fractions.

The data presented above, indicate that NO_x control techniques which alter the overall boiler temperature profile, or change the particulate mass emissions or particle size distribution can affect the concentration of trace metals emitted from the collector.

Tests for polycyclic organic matter (POM) have been conducted (Reference 6-16). The data from a stoker coal-fired boiler (chain grate) is presented in Table 6-5. The data are incomplete due to the lack of sufficient gas stream samples for analyses. Though organic species are present, their general trend as a function of NO_x control is not known.

EPA-sponsored tests of two industrial spreader stokers indicate only a possible slight increase in organic emissions under low-NO_x firing conditions (LEA, OFA) as compared to those under baseline conditions (References 6-22 and 6-23).

The above emission data was presented for combustion modifications only. Low NO_x burners and ammonia injection, considered to be advanced control methods, are still in the development stages. Actual incremental emission data are not available.

6.4 ENVIRONMENTAL IMPACTS OF NO_x CONTROLS FOR RESIDUAL OIL-FIRED BOILERS

Oil-fired industrial boilers fall into two major equipment categories. These are packaged watertube and firetube boilers. The recommended NO_x control levels for industrial boilers firing residual oil fuel are presented in Table 3-6. The recommended NO_x control techniques from Section III are low excess air, staged combustion, low NO_x burners and ammonia injection.

Table 6-6 presents incremental emission data collected during two recent test programs (References 6-15 and 6-17). This information is presented graphically in Figures 6-5 through 6-8.

Figure 6-5 presents all changes in low excess air incremental emission data as a function of changes in NO_x emission levels. All low NO_x control conditions that meet any of the recommended control levels results in an increase in CO emissions. Generally, the more the NO_x emissions are reduced, the higher the CO emission rate. As with coal fired boilers, hydrocarbon levels remain relatively unchanged.

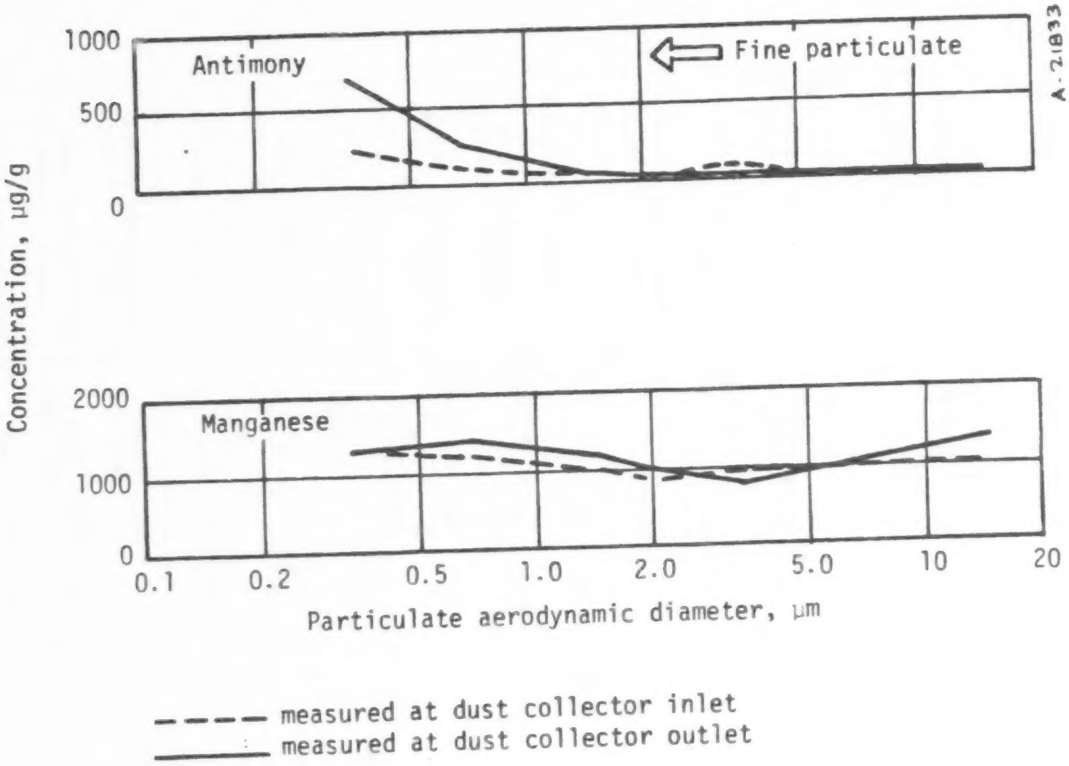


Figure 6-4. Trace element concentration in fine particulate (Reference 6-16).

TABLE 6-5. EMISSION RATES OF POLYCYCLIC ORGANIC MATTER (POM) FROM A COAL-FIRED CHAIN-GRATE STOKER BOILER (Reference 6-16)

Run No.	POM	In Coal		In Hopper Ash		In Stack Gases			
						Particulate		Vapor	
		g	%	g	%	g	%	g	%
9	7,12 Dimethylbenz(a)anthracene	None dectected		None detected		Insufficient sample		None detected	
10		None detected		2.26	--	Insufficient sample		Trace	
11		None detected		1.39	--	Insufficient sample		None detected	
9	Benzo(a)pyrene	109	100	37	34	Insufficient sample		None detected	
10		245	100	92.6	38	Insufficient sample		None detected	
11		18.8	100	651	3462	Insufficient sample		None detected	
9	3 Methylcholanthrene	None detected		None detected		Insufficient sample		None detected	
10		None detected		None detected		Insufficient sample		None detected	
11		None detected		None detected		Insufficient sample		None detected	
9	Dibenz(a,h)anthracene	610	100	None detected		Insufficient sample		None detected	
10		822	100	None detected		Insufficient sample		None detected	
11		673	100	None detected		Insufficient sample		None detected	

TABLE 6-6. INCREMENTAL EMISSIONS FROM RESIDUAL OIL-FIRED BOILERS (REFERENCE 6-15)

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
A	35/44 (120)/(150)	Watertube	Baseline (5.0)	165	--	CO UHC SO_3 Part.	0 7 -- --	-- -- -- --
	35/44 (120)/(150)	Watertube	Low Excess Air (3.1)	138	-27	CO UHC SO_3 Part.	0 5 -- --	0 -2 -- --
B	8.4/20 (27)/(68)	Watertube	Baseline (5.3)	115	--	CO UHC SO_3 Part.	0 -- -- 140	-- -- -- --
	8.1/20 (27)/(68)	Watertube	Low Excess Air (4.9)	101	-14	CO UHC SO_3 Part.	10 -- -- --	+10 -- -- --
C	18/23 (61)/(79)	Watertube	Baseline (3.3)	148	--	CO UHC SO_3 Part.	0 2 -- 780	-- -- -- --
	19/23 (64)/(79)	Watertube	Low Excess Air (2.7)	143	-5	CO UHC SO_3 Part.	70 2 -- --	+70 0 -- --

[a] No data available on noncriteria emissions

Continued

T-1449

TABLE 6-6. Continued

Boiler Test Series	System			NO$_x$ Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO$_x$ Control (Excess O$_2$, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
D	9.3/12 (32)/(40)	Watertube	Baseline (4.3)	109	--	CO UHC SO$_3$ Part.	0 3 12 62	-- -- -- --
	9.3/12 (32)/(40)	Watertube	Low Excess Air (4.0)	98	-11	CO UHC SO$_3$ Part.	9 0 -- 41	+9 -3 -- -21
E	10/13 (36)/(45)	Watertube	Baseline (3.0)	183	--	CO UHC SO$_3$ Part.	0 0 2 46	-- -- -- --
	11/13 (37)/(45)	Watertube	Low Excess Air (1.6)	136	-47	CO UHC SO$_3$ Part.	41 5 -- --	+41 +5 -- --
	10/13 (36)/(45)	Watertube	Overfire Air (2.9)	97	-86	CO UHC SO$_3$ Part.	19 4 -- 59	+19 4 -- +13
	10/13 (36)/(45)	Watertube	Overfire Air (3.0)	90	-93	CO UHC SO$_3$ Part.	31 0 -- --	+31 0 -- --

[a]No data available on noncriteria emissions

Continued

T-1449

TABLE 6-6. Continued

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
F	4.1/5.1 (14)/(17)	Watertube	Baseline (3.1)	95	--	CO	0	--
						UHC	0	--
						SO_3	--	--
						Part.	13	--
	4.1/5.1 (14)/(17)	Watertube	Low Excess Air (0.9)	70	-25	CO	34	+34
						UHC	--	--
						SO_3	--	--
						Part.	--	--
	4.1/5.1 (14)/(17)	Watertube	Overfire Air (2.4)	61	-34	CO	53	+53
						UHC	1	+1
						SO_3	--	--
						Part.	--	--
	3.9/5.1 (14)/(17)	Watertube	Overfire Air (3.25)	102	+7	CO	0	0
						UHC	0	0
						SO_3	--	--
						Part.	--	--
	4.1/5.1 (14)/(17)	Watertube	Overfire Air (3.1)	75	-20	CO	0	0
						UHC	3	3
						SO_3	--	--
						Part.	12	-2
	4.1/5.1 (14)/(17)	Watertube	Baseline (2.9)	91	--	CO	0	--
						UHC	0	--
						SO_3	2	--
						Part.	13	--
	4.1/5.1 (14)/(17)	Watertube	Low Excess Air (2.25)	77	-14	CO	48	+48
						UHC	0	0
						SO_3	--	--
						Part.	--	--

[a]No data available on noncriteria emissions

Continued

T-1449

TABLE 6-6. Continued

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
F (Cont.)	4.1/5.1 (14)/(17)	Watertube	Overfire Air (3.0)	84	-7	CO UHC SO_3 Part.	27 13 -- --	+27 +13 -- --
	4.1/5.1 (14)/(17)	Watertube	Overfire Air (2.9)	73	-18	CO UHC SO_3 Part.	10 0 -- --	+10 0 -- --
G	4.0/5.1 (14)/(17)	Watertube	Baseline (3.0)	122	--	CO UHC SO_3 Part.	1 2 4 36	-- -- -- --
	4.1/5.1 (14)/(17)	Watertube	Low Excess Air (1.0)	84	-38	CO UHC SO_3 Part.	62 4 3 26	+61 +2 -1 -10
	4.0/5.1 (14)/(17)	Watertube	Overfire Air (3.1)	85	-37	CO UHC SO_3 Part.	8 1 3 32	+7 -1 -1 -4
H	11/13 (38)/(45)	Watertube	Baseline (2.9)	146	--	CO UHC SO_3 Part.	8 - 22 66	-- -- -- --
	11/13 (39)/(45)	Watertube	Low Excess Air (1.6)	107	-39	CO UHC SO_3 Part.	21 -- 10 44	+13 -- -12 -22

[a] No data available on noncriteria emissions

Continued

T-1449

TABLE 6-6. Concluded

Boiler Test Series	System			NO$_x$ Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO$_x$ Control (Excess O$_2$, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
H (Cont.)	11/13 (37)/(45)	Watertube	Overfire Air (3.0)	86	-60	CO UHC SO$_3$ Part.	10 -- -- --	+2 -- -- --
I	5.4/7.3 (18)/(30)	Watertube	Baseline (9.3)	184	--	CO UHC SO$_3$ Part.	<10 -- -- --	-- -- -- --
	5.4/7.3 (8)/(30)	Watertube	Low Excess Air (7.6)	174	-10	CO UHC SO$_3$ Part.	<10 -- -- --	0 -- -- --
	5.4/7.3 (18)/(30)	Watertube	Low Excess Air (5.5)	156	-28	CO UHC SO$_3$ Part.	<10 -- -- --	0 -- -- --
	5.5/7.3 (19)/(30)	Watertube	Low Excess Air (4.5)	127	-57	CO UHC SO$_3$ Part.	<10 -- -- --	0 -- -- --
	5.5/7.3 (19)/(30)	Watertube	Low Excess Air (4.3)	140	-44	CO UHC SO$_3$ Part.	<10 -- -- --	0 -- -- --
	5.5/7.3 (19)/(30)	Watertube	Low Excess Air (4.2)	94	-90	CO UHC SO$_3$ Part.	1232 -- -- --	+1232 -- -- --
	5.4/7.3 (19)/(30)	Watertube	Low Excess Air (3.6)	113	-71	CO UHC SO$_3$ Part.	103 -- -- --	+103 -- -- --

[a] No data available on noncriteria emissions

T-1449

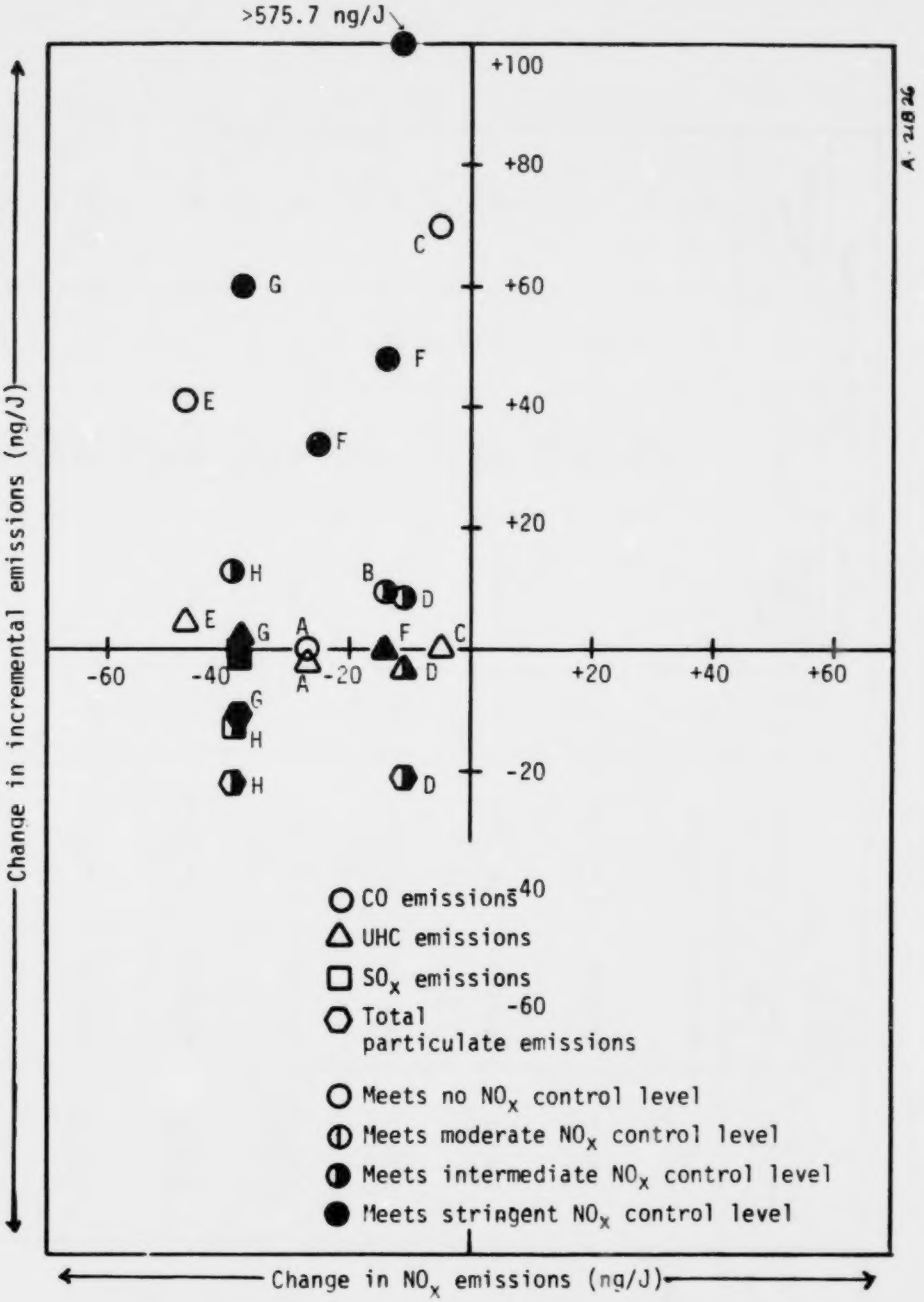


Figure 6-5. Change in incremental emissions with low excess air NO_x control for residual oil-fired watertube industrial boilers (References 6-15 and 6-17).

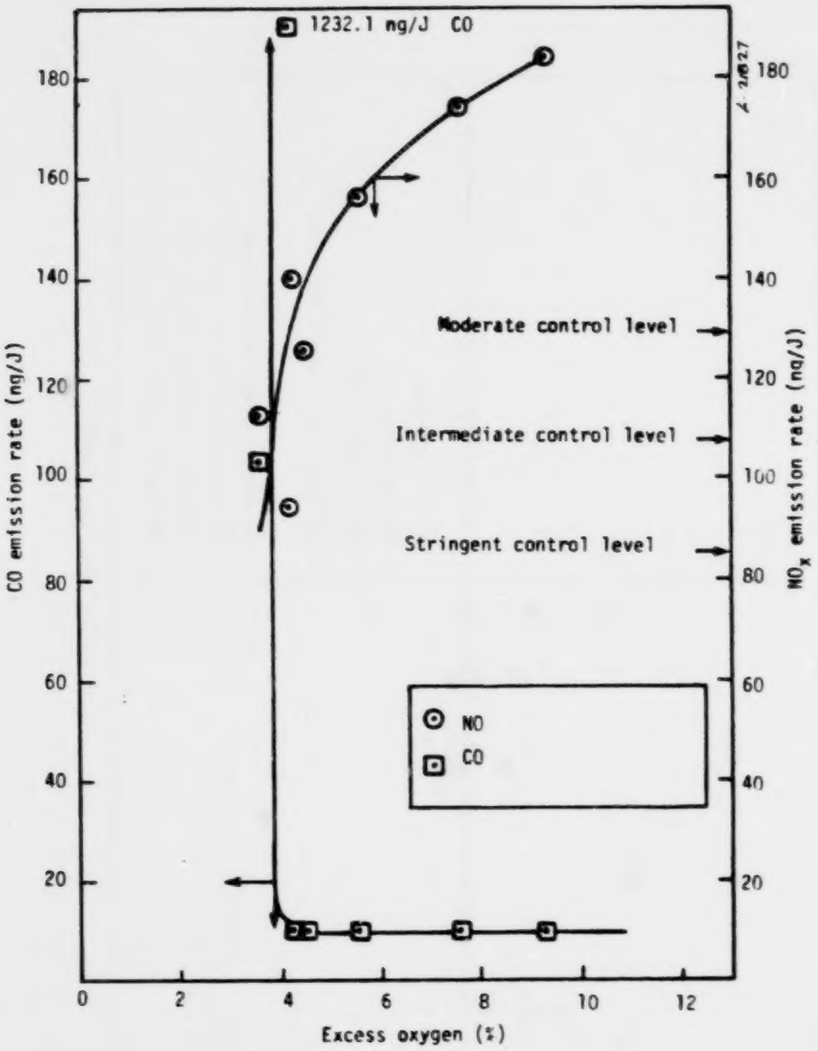


Figure 6-6. Changes in CO and NO$_x$ emissions with reduced excess oxygen for a residual oil-fired watertube industrial boiler (Reference 6-17).

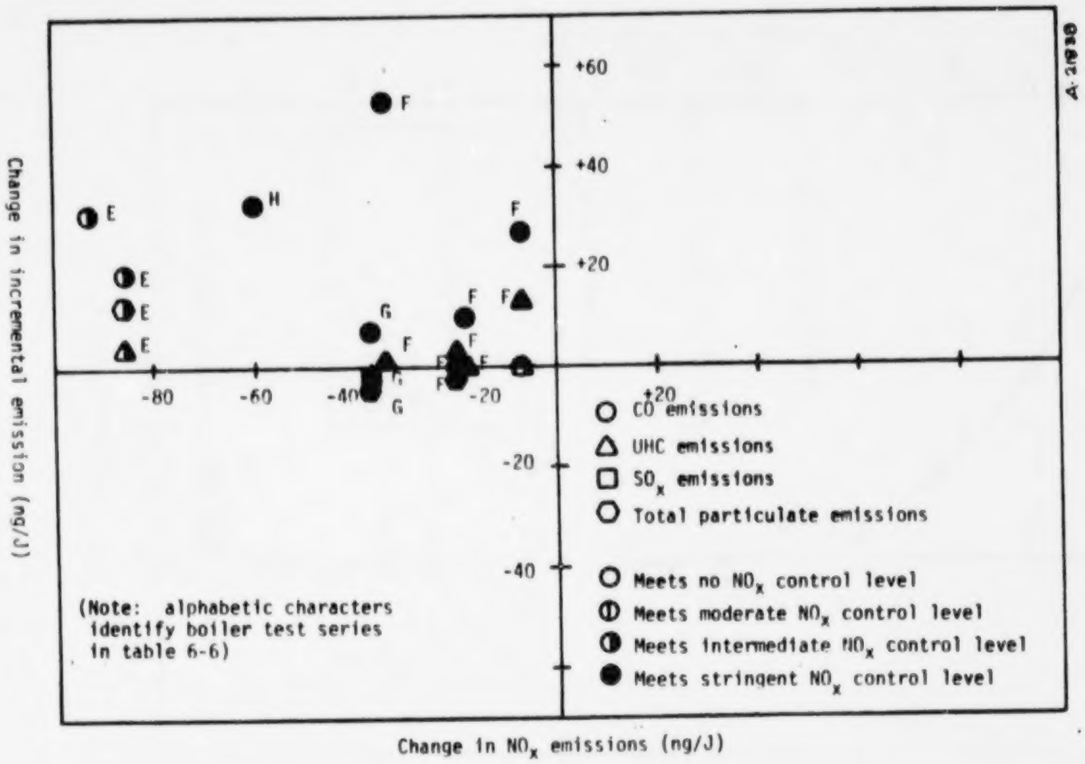


Figure 6-7. Change in incremental emissions with overfire air NO$_x$ control for residual oil-fired watertube industrial boilers (References 6-15 and 6-17).

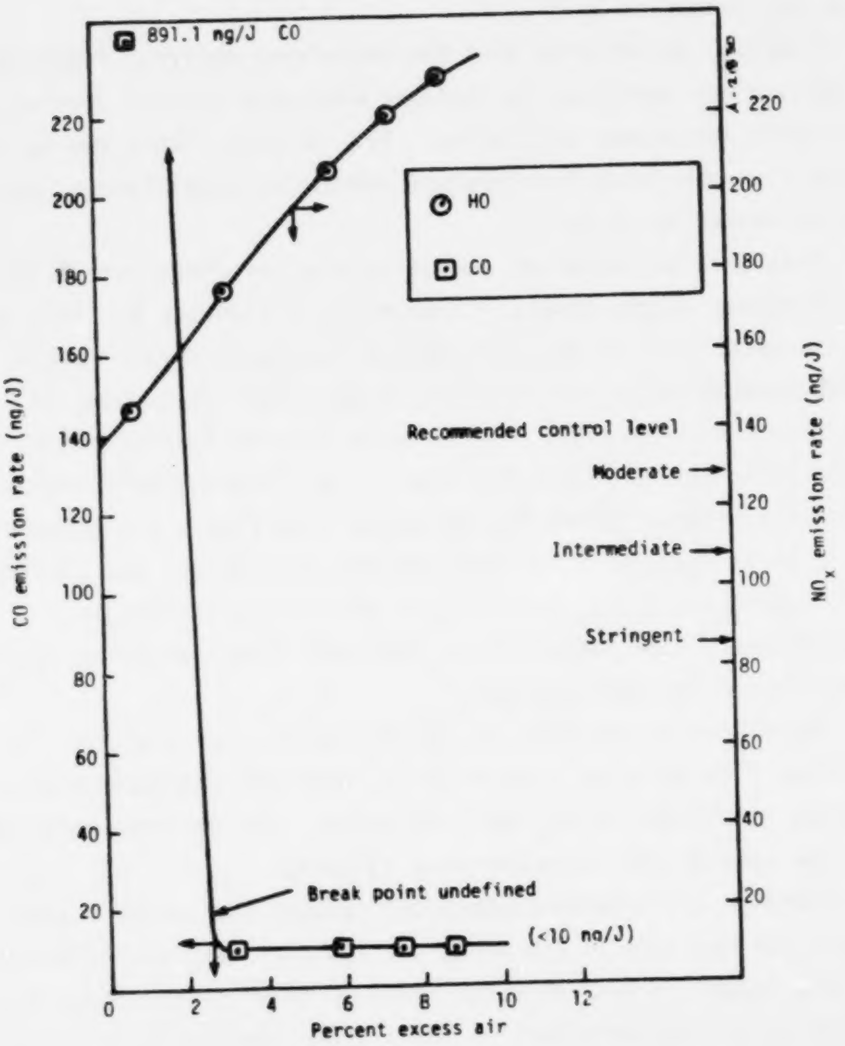


Figure 6-8. Change in CO and NO$_x$ emissions with decreasing excess oxygen for a residual oil-fired firetube industrial boiler (Reference 6-17).

A trend for sulfate emissions similar to that of coal-fired boilers is not apparent for residual oil-fired boilers. However, a test from Series H was conducted with an excess oxygen content of 1.6 percent, and tests from Series G with 1.55 percent and 1.0 percent excess O_2 levels. Though marginally conclusive, the higher O_2 level test does have the highest SO_3 oxidation level.

Finally, as was true with the coal-fired boilers, Figure 6-5 shows that particulate emissions for boilers with dust control devices are reduced with low excess air firing. This is most likely due to increased particle size resulting from reduced combustion completeness, making the particles easier to catch.

Test data collected on a watertube boiler (Reference 6-17) over a range of excess oxygen levels is presented in Figure 6-6. This figure shows the reductions in NO_x with decreasing excess oxygen levels. Complete combustion occurs until the oxygen level is reduced to approximately 4.25 percent. The emission rate of CO then climbs sharply. The data presented in Figure 6-5 show a significantly more scattered relationship between CO and NO_x emissions than Figure 6-6 suggests. However, it is reasonable to conclude that each boiler has similar emission characteristics, but fuel/air mixing, fuel nitrogen concentrations, flame temperatures, and many other variables, are responsible for the data scatter.

The effect of overfire air on NO_x control is shown in Figure 6-7. The emission rate of CO is generally increased with increasing reductions in NO_x emission rates. The emission rates of UHC remain the same or are increased only slightly.

Overfire air (staged combustion) reduces the excess oxygen available for reaction in the primary combustion zone of the boiler. Since less oxygen is available for reaction under these conditions, a reduction in sulfate emissions in the primary zone could be expected. Addition of secondary combustion air may quench the reaction, resulting in reduced overall SO_3. Figure 6-7 shows decreases in sulfate emissions on both tests conducted. (The potential for trace metal catalytic oxidation will be discussed later in this section.)

Finally, the trend established in Figures 6-1 and 6-5 of reduced particulate emissions, has one exception, test condition E. The boiler located at this test site does not have a dust control device. Since reduced combustion efficiency results in increased particulate size and emission rate, this facility would be expected to have increased particulate emissions without dust control devices. Again, sufficient data is not available to establish overall particulate removal efficiencies.

A second series of tests conducted at various excess oxygen contents was reported in Reference 6-17. These data were collected on a firetube boiler and illustrate the relationship between NO_x and CO emission rates as a function of excess oxygen concentrations. As in Figure 6-6, a distinct increase in CO emissions is noted as excess oxygen reaches the lower practical operating limit. Unfortunately, this lower limit is not clearly defined. It is seen that CO emissions drastically increase before the NO_x emission rate reaches even the moderate control level.

A set of size distribution tests were conducted during the field test series reported in Reference 6-16. It was found that the combustion of oil fuel produced a larger proportion of particulates having an aerodynamic diameter less than 3 micrometers than did coal fuel. A comparison of Table 6-4 for coal and Table 6-7 for residual oil shows this trend.

Other data collected during various low NO_x control conditions were reported in References 6-15 and 6-18. The data are presented in Figures 6-9 through 6-11. Though test number 132 does not follow the trend, generally an increase in particle size as excess air levels are decreased can be seen. The remaining combustion modifications and combinations of modifications also indicate an increased particle size but the degree of change is mixed.

A recently completed field test program on an oil-fired industrial boiler (Reference 6-18) is the only source of organic emission data identified. The organic species proved very difficult to identify, with most sample quantities insufficient to allow for analysis.

No polychlorinated biphenyls (PCB) were identified during the oil tests. The concentration of polycyclic organic matter (POM) contained in the various sample train fractions is shown in Table 6-8. The most complete analysis was obtained from the organic absorbent (XAD-2) resin.

TABLE 6-7. EFFECT OF OVERFIRE AIR NO_x CONTROL ON PARTICLE SIZE DISTRIBUTION[a] FOR A RESIDUAL OIL-FIRED WATERTUBE BOILER (Reference 6-16)

						Actual D_{50} of Stage No.[b]						Cyclone, Stage and Filter Catch							
												Stage No.							
Fuel Type	Burner Type	Test Load GJ hr^{-1}	NO_x ng/J	Impact Flow $cm^3\ s^{-1}$	D_{50} Cycl. µm	1 µm	2 µm	3 µm	4 µm	5 µm	Cyclone mg	1 mg	2 mg	3 mg	4 mg	5 mg	Filter mg	Total Catch mg	Comments
No. 6	Steam	34	111	22.6	--	3.62	2.17	1.45	0.72	0.36	None	2.812	1.616	0.668	0.456	0.312	2.700	8.564	Baseline
No. 6	Steam	34	97.6	22.7	--	3.61	2.17	1.44	0.72	0.36	None	3.112	1.372	0.596	0.332	0.196	2.344	7.952	Low NO_x

T-1452

[a] Particle size distribution determined by use of a Brink model "B' cascade impactor

[b] D_{50} identifies the size fraction in micrometers. Particulates with an aerodynamic diameter greater than the D_{50} cut point will be captured. Increasing stage number corresponds to decreasing particle size.

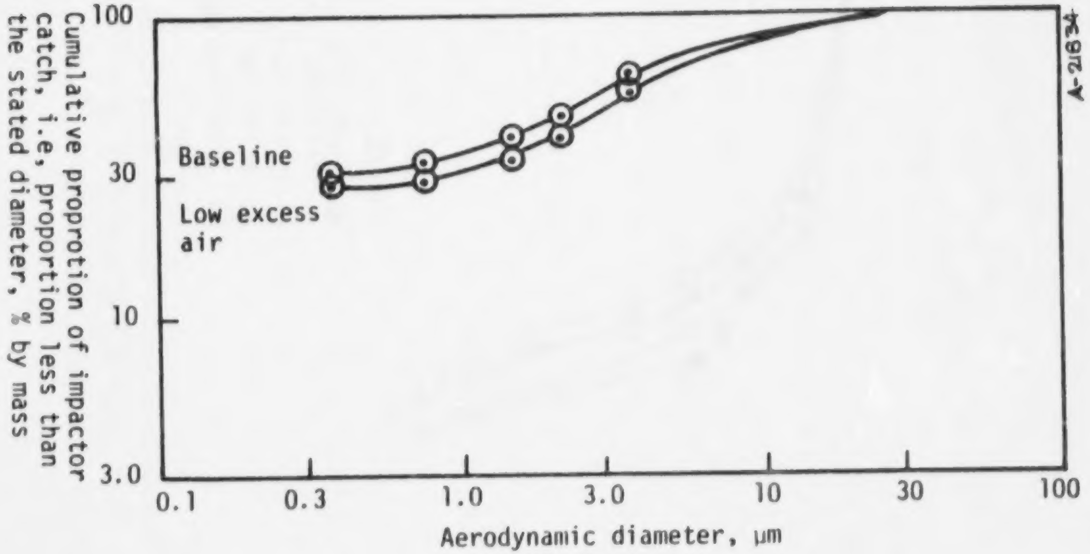


Figure 6-9. Effect of low excess air NO_x control on particle size distribution for a residual oil-fired watertube industrial boiler. (Reference 6-15)

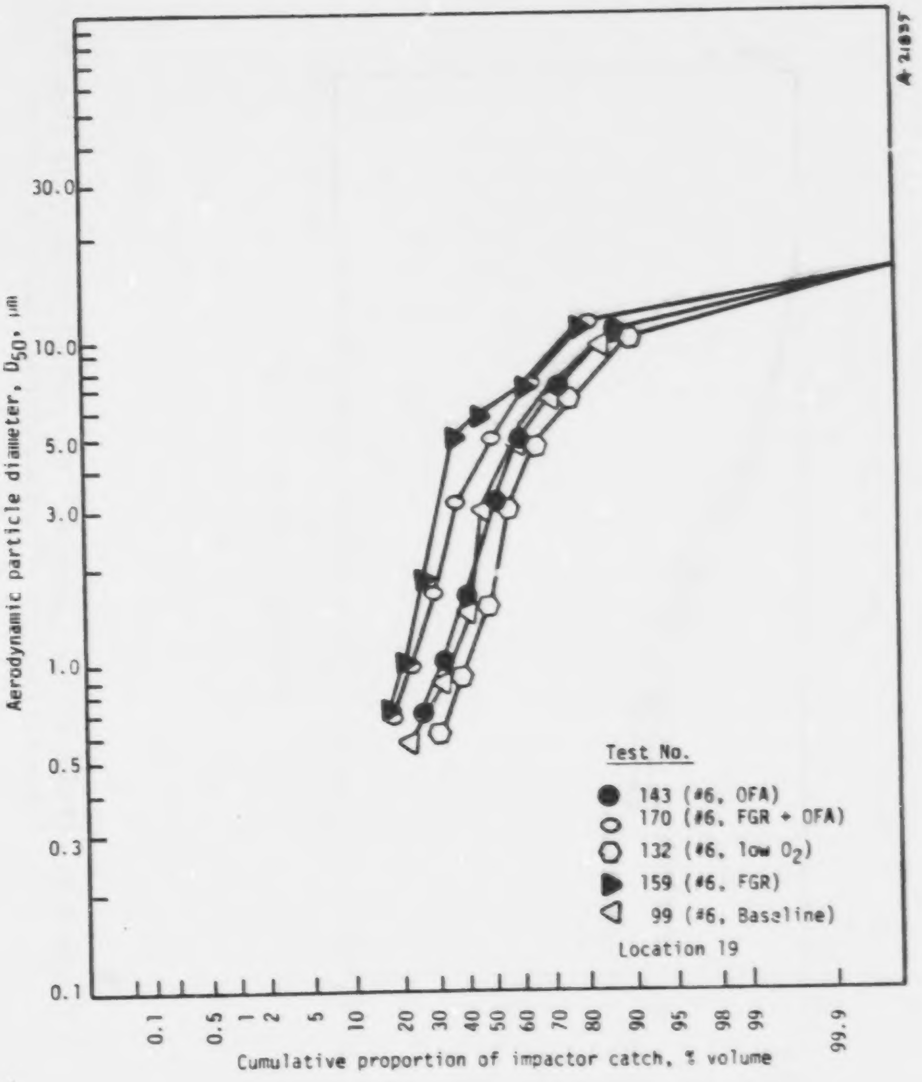


Figure 6-10. Effect of NO_x controls on particle size distribution for a residual oil-fired watertube industrial boiler. (Reference 6-18)

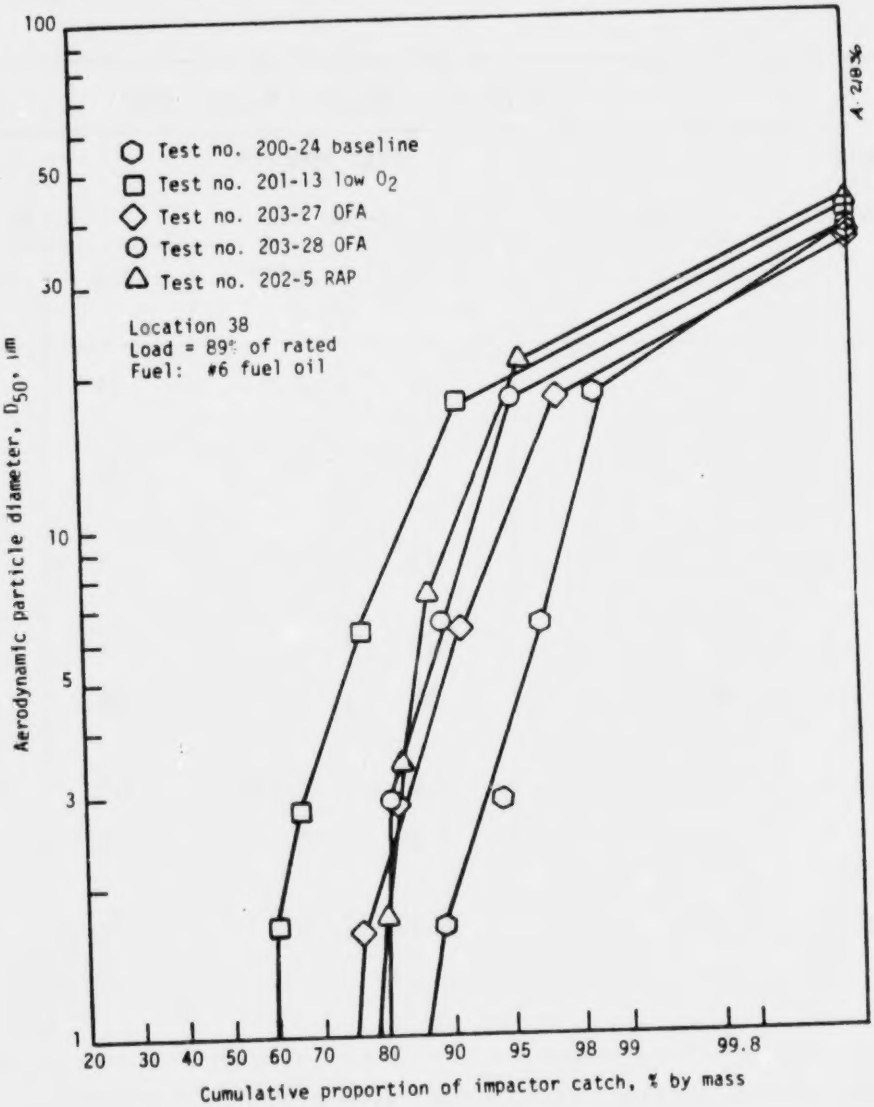


Figure 6-11. Effect of NO_x controls on particle size distribution for a residual oil-fired watertube industrial boiler. (Reference 6-18)

TABLE 6-8. EFFECT OF COMBINED LOW EXCESS AIR, STAGED COMBUSTION, AND FLUE GAS RECIRCULATION ON POLYCYCLIC ORGANIC MATTER (POM) EMISSIONS FROM A RESIDUAL OIL-FIRED INDUSTRIAL BOILER (Reference 6-18)

Sample Train Fraction	Polycyclic Organic Matter (POM)					
	Test Number*					
	2-Baseline		3-Low NO_x		4-Low NO_x	
	μg/g	μg/m^3	μg/g	μg/m^3	μg/g	μg/m^3
10 μm solids	IS+	--	1	0.1	IS	--
3 μm solids	IS	--	IS	--	IS	--
1 μm solids	IS	--	IS	--	IS	--
Filters	IS	--	IS	--	IS	--
Solids section wash	NR°	--	NR	--	NR	--
XAD-2 resin	0.005	0.04	0.0008	0.006	<0.1	<0.8
Organic module rinse	IS	--	1.45	50	IS	--
Condensate	<0.001	<0.24	0.002	0.5	NR	--
Impinger 1-3	--	--	--	--	--	--

*Test 1 results were obtained using a fuel with a different analysis.
+Insufficient sample.
°Not recorded.

The results of these tests are presented in Table 6-9. The results show a significant reduction in POM in the XAD-2 resin for the low NO_x test compared to that for baseline conditions. The test results are definitely not in line with the expected trends. However, without complete analysis of all fractions, a conclusion concerning the total gas stream cannot be made.

Trace element emission data are also limited. The same study which provided the POM data, above, provided the trace element data reported below (Reference 6-18). A combination of reduced excess air staged combustion and flue gas recirculation resulted in an increase in particulate emissions of from 30 to 60 percent over baseline conditions. Tables 6-10 through 6-12 present the results of the element partitioning study as a result of the increased particulate loading. Comparison of test 3 (low NO_x) with test 2 (baseline) indicates that calcium, chromium, iron, manganese, titanium and zinc were increased by 10 to 90 percent in the solid particulate less than 3 micrometers. These same elements, plus barium, cobalt, and copper were increased by over 20% in the total amount of solid particulate collected.

Comparison of the concentration of arsenic, cobalt, copper, iron, manganese, nickel, vanadium, zinc, chloride and sulfates at each size fraction shows a clear shift in concentration towards the smaller particle sizes during low NO_x operation. The remaining species were not present in sufficient quantities to allow an assessment.

It appears that, for this particular boiler, an increase in trace metal emissions, in proportion to increased particulate, occurs with increased NO_x control. A shift towards increased trace metal concentration in smaller particulate can also be seen.

The NO_x control data, unfortunately, is still very limited, presenting information only on a combination of control technologies, and only for one boiler. More data must be collected before firm conclusions can be presented.

The above emission data were presented for combustion modifications only. Low NO_x burners and ammonia injection, considered to be advanced control method, are still in the development stages. Actual incremental emission data are not available.

TABLE 6-9. EFFECT OF NO_x CONTROL ON POLYCYCLIC ORGANIC MATTER (POM) EMISSIONS FROM A RESIDUAL OIL-FIRED BOILER: XAD-2 RESIN TEST ONLY[a] (Reference 6-18)

POM Component[b]	Baseline		Low NO_x	
	$\frac{\text{ng POM}}{\text{g Particulate}}$	$\frac{\text{ng POM}}{\text{m}^3\text{ Flue gas}}$	$\frac{\text{ng POM}}{\text{g Particulate}}$	$\frac{\text{ng POM}}{\text{m}^3\text{ Flue gas}}$
Anthracene	3.2	24	0.45	3.4
Phenanthrene	--	--	0.02	0.1
Methyl Anthracenes	0.2	1.6	0.12	0.9
Fluoranthene	1.2	9.0	0.13	0.9
Pyrene	0.05	0.4	0.05	0.4
Benzo(c)phenanthrene	0.002	0.02	--	--
Chrysene	0.03	0.19	0.004	0.03
Benzo Fluoranthenes	0.007	0.05	0.007	0.05
Benz(a)pyrene	0.004	0.032	--	--
Benz(e)pyrene	0.004	0.032	--	--
Total POM	4.74	35.5	0.78	5.8

[a] Low NO_x condition: combined low excess air, staged combustion, and flue gas recirculation.

[b] Analysis by gas chromatograph -- mass spectrometry.

TABLE 6-10. EFFECT OF COMBINED LOW EXCESS AIR, STAGED COMBUSTION, AND FLUE GAS RECIRCULATION ON TRACE SPECIES EMISSIONS FROM A RESIDUAL OIL-FIRED INDUSTRIAL BOILER (Reference 6-18)

	Total Emission Concentrations by Atomic Absorption, $\mu g/m^3$			Total Emission Concentrations by Spark Source Mass Spectrometry, $\mu g/m^3$	
Test	2	3[a]	4[a]	2	3
Condition	Baseline	Low NO$_x$	Low NO$_x$	Baseline	Low NO$_x$
Antimony	< 380	< 540	< 350	11	160
Arsenic	6.5 < 15	59 < 64	55	6.5	6 < 12
Barium	95 < 210	640 < 740	800 < 850	MC	640
Beryllium	< 6	< 8.9	< 6	0.055 < 3	0.3 < 2
Cadmium	13	4.8 < 12	1.1 < 6	7.5 < 13	0.09 < 5
Calcium	650	2000	440 < 460	2000 < MC	67 < MC
Chromium	750	740	530	960	500
Cobalt	65 < 130	79 < 150	18 < 85	8 < MC	94
Copper	32	39 < 44	95	49	130
Iron	4300	4700	3100	1300 < MC	1100
Lead	45 < 70	9.9 < 21	< 15	52 < 67	54
Manganese	70	99	65	69	64
Mercury	< 1.9	0.06 < 21	2	NR	NR
Nickel	1300 < 1400	1600	2200	180 < MC	240 < MC
Selenium	< 12	9.9 < 290	< 11	2 < 5	100 < 110
Tellurium	< 300	< 450	< 290	0.04 < 3	0.2 < 3
Tin	< 750	< 1000	< 700	0.4 < 8	12
Titanium	70 < 1600	120 < 2500	20 < 100	53	580
Vanadium	3200 < 3400	3400 < 3600	2400	8 < MC	9 < MC
Zinc	370	810	3300	MC	680
Chloride	12000	3500	6000	4.3	2100
Fluoride	170 < 180	54 < 79	24 < 33	23	170
Nitrates	130	110 < 120	85	--	--
Sulfates	18000	18000	21000	--	--

[a] Tests 3 and 4 are duplicate runs.

TABLE 6-11. TRACE SPECIES EMISSIONS FROM A RESIDUAL OIL-FIRED INDUSTRIAL BOILER UNDER BASELINE CONDITIONS (TEST 2) (REFERENCE 6-18)

Sample Type	Nozzle, Probe, 10 µm Cyclone Solids		3 µm Cyclone Solids		1 µm Cyclone Solids		Filters		Solid Section Wash	
Sample Number	566		716		720		538		19-2A	
Sample Weight/Vol.	1.6620 g		0.4443 g		0.2196 g		0.4157 g		1605 ml	
Units	µg/g	µg/m³	µg/g	µg/m³	µg/g	µg/m³	µg/g	µg/m³	µg/ml	µg/m³
Antimony	< 38	< 3.2	< 210	< 4.7	< 230	< 2.7	< 500	< 10	< 0.5	< 40
Arsenic	< 1.5	< 0.13	33	0.73	< 10	< 0.11	200	4.2	0.019	1.4
Barium	38	3.2	460	10	6030	66	800	17	< 0.1	< 8
Beryllium	< 0.8	< 0.065	< 4.2	< 0.093	< 5	< 0.055	< 10	< 0.2	< 0.005	< 0.4
Cadmium	0.8	0.065	< 4.2	< 0.093	< 5	< 0.055	< 10	< 0.2	0.005	0.4
Calcium	1900	160	1900	42	3500	38	4800	100	0.49	39
Chromium	72	6	140	3.1	310	3.4	240	5	0.09	7.2
Cobalt	120	10	310	6.7	940	10	1600	33	< 0.2	< 16
Copper	46	3.8	50	1.1	100	1.1	460	9.6	0.06	4.8
Iron	5400	450	7200	160	32000	350	21000	440	2.6	210
Lead	150	13	< 20	< 0.44	< 25	< 0.27	1000	21	0.14	11
Manganese	51	4.3	75	1.7	210	2.3	250	5.2	0.17	14
Mercury	< 0.03	< 0.0025	< 0.17	< 0.0038	< 0.2	< 0.0022	< 0.4	< 0.008	< 0.005	< 0.4
Nickel	1900	160	2200	49	9000	99	30000	620	0.77	62
Selenium	< 1.5	< 0.13	< 8	0.19	< 10	< 0.11	< 20	< 0.42	< 0.01	0.8
Tellurium	< 38	< 3.2	< 210	< 4.7	< 250	< 2.7	< 500	< 10	< 0.3	< 24
Tin	< 76	< 6.3	< 420	< 9.3	< 500	< 5.5	<1000	< 21	< 1	< 80
Titanium	< 460	< 38	<1200	< 27	2500	27	<3000	< 62	< 1	< 80
Vanadium	6300	520	10000	220	43000	470	89000	1800	2.5	200
Zinc	400	33	400	8.9	1300	14	4900	100	1.7	140
Chloride	279	23	NES	NES	NES	NES	11600	240	2.1	170
Fluoride	205	17	134	3	909	10	< 2	< 0.04	< 0.1	< 8
Nitrates	113	9.4	NES	NES	NES	NES	39.5	0.82	0.24	19
Sulfates	14200	1200	NES	NES	NES	NES	457000	9500	7.0	560

TABLE 6-12. TRACE SPECIES EMISSIONS FROM A RESIDUAL OIL-FIRED INDUSTRIAL BOILER UNDER LOW NO_x CONDITIONS (TEST 3)[a] (REFERENCE 6-18)

Sample Type	Nozzle, Probe, 10 µm Cyclone Solids		3 µm Cyclone Solids		1 µm Cyclone Solids		Filters		Solid Section Wash	
Sample Number	722		723		726		539		19-3A	
Sample Weight/Vol.	2.4163 g		1.0724 g		0.2120 g		0.9974 g		1839 ml	
Units	µg/g	µg/m³	µg/g	µg/m³	µg/g	µg/m³	µg/g	µg/m³	µg/ml	µg/m³
Antimony	< 50	< 6	< 2500	< 130	< 830	< 9	< 170	< 8	< 0.5	< 46
Arsenic	4	0.5	< 100	< 5	< 33	< 0.4	33	1.6	0.01	0.9[illegible]
Barium	480	57	< 1000	< 53	< 330	< 4	730	36	< 0.1	< 9
Beryllium	< 1	< 0.12	< 50	< 3	< 17	< 0.2	< 3.3	< 0.2	< 0.005	< 0.5
Cadmium	< 1	< 0.12	< 50	< 3	< 17	< 0.2	< 3.3	< 0.2	< 0.005	< 0.5
Calcium	1900	230	3500	190	3000	31	3100	150	15	1400
Chromium	69	8	950	50	300	3.1	180	8.9	0	0
Cobalt	104	12	450	24	300	3.1	807	40	< 0.2	< 18
Copper	43	5	< 50	< 3	< 150	< 2	200	9.9	0.11	10
Iron	5200	620	4400	230	6500	68	20000	1000	1.8	160
Lead	NES	--	NES	--	NES	--	NES	--	0.11	10
Manganese	49	6	200	11	117	1.2	160	7.9	0.16	15
Mercury	0.5	0.06	< 2	< 0.1	< 0.67	< 0.007	< 0.13	< 0.006	< 0.005	< 0.5
Nickel	970	120	1700	90	3000	31	13000	640	0.5	46
Selenium	< 2	0.24	< 5000	< 270	< 33	< 0.4	< 6.7	< 0.3	0.04	3.6
Tellurium	< 50	6	< 2500	< 130	< 830	< 9	< 170	< 8	< 0.3	< 27
Tin	< 100	12	< 5000	< 270	< 1700	< 18	< 330	< 16	< 1	< 91
Titanium	600	72	< 15000	< 800	5000	52	< 1000	< 49	< 1	< 91
Vanadium	5400	650	7000	370	14000	150	43000	2100	1.4	130
Zinc	281	34	250	13	350	3.7	3000	150	0.49	45
Chloride	< 30	< 4	< 97	< 5	NES	--	1700	84	< 0.5	< 46
Fluoride	54	6.5	NES	--	NES	--	< 1	< 0.05	< 0.1	< 9
Nitrates	43	5.1	67	3.6	NES	--	46	2.3	0.26	24
Sulfates	8910	1100	14000	740	NES	--	170000	8400	12	1100

[a] Low NO_x condition: combined low excess air, staged combustion, and flue gas recirculation.

Due to the comparative high cost of this technique, the ammonia injection process will probably not be feasible on small size boilers such as firetubes and package watertubes unless stringent emission levels are required. In addition, since these industrial units are generally not base loaded, that is they do not operate at a steady continuous load, the variable heat input will cause significant flue gas temperature fluctuations which will reduce the performance of the control technique.

6.5 ENVIRONMENTAL IMPACTS OF NO_x CONTROLS FOR DISTILLATE OIL AND NATURAL GAS-FIRED BOILERS.

Distillate oil and natural gas-fired industrial boilers are generally packaged firetube boilers. The recommended NO_x control techniques are presented in Table 3-10 for distillate oil and Table 3-11 for natural gas. The recommended emission levels for both fuels are presented in Table 3-6.

Table 6-13 presents the incremental emission data available for distillate oil-fired boilers. Table 6-14 presents the incremental emission data available for natural gas-fired boilers.

Figure 6-12 presents the data for CO emissions with the various types of NO_x control techniques for distillate oil fuels. Carbon monoxide emissions increase in all cases where NO_x reductions occurred. Flue gas recirculation resulted in the largest decrease in NO_x emission rate and met the stringent control level in both cases. All other control types met the intermediate control level, with CO emissions varying from no change to substantial increase. Low excess air resulted in the largest increases.

Figure 6-13 presents the incremental emission data for unburned vapor phase hydrocarbons from distillate oil-fired boilers. Generally there appears to be no change with NO_x emission reduction.

Data on the emissions for natural gas-fired boilers are presented in Figure 6-14. Low excess air NO_x control results in the largest incremental increases in CO emissions. However, the NO_x emissions are generally reduced to only moderate or intermediate levels. The best control technique for reaching the required NO_x levels without severe incremental emission impact is flue gas recirculation. All other control techniques are mixed in their ability to control NO_x and their effects on other emissions. Figure 6-15 presents additional CO emission data as a

TABLE 6-13. INCREMENTAL EMISSIONS FROM DISTILLATE OIL-FIRED INDUSTRIAL BOILERS

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
A	6.9/9.3 (23)/(33)	Watertube	Baseline (5.9)	66	--	CO	0	--
						UHC	--	--
						SO_3	7	--
						PART	20	--
	7.0/9.3 (24/(33)	Watertube	Low Excess Air (2.8)	57	-9	CO	6	+6
						UHC	--	--
						SO_3	--	--
						PART	--	--
B	26/32 (89)/(110)	Watertube	Baseline (5.7)	115	--	CO	0	--
						UHC	--	--
						SO_3	8	--
						PART	10	--
	26/32 (89)/(110)	Watertube	Low Excess Air (3.8)	--	--	CO	0	0
						UHC	--	--
						SO_3	--	--
						PART	--	--
C	2.0/2.9 (7)/(10)	Firetube	Baseline (7.2)	121	--	CO	0	--
						UHC	24	--
						SO_3	1	--
						PART	23	--
	1.5/2.9 (5)/(10)	Firetube	Low Excess Air (3.6)	85	-36	CO	0	0
						UHC	5	-19
						SO_3	--	--
						PART	--	--
D	4.1/5.1 (14)/(18)	Watertube	Baseline (3.6)	37	--	CO	17	--
						UHC	--	--
						SO_3	6	--
						PART	17	--

[a] No data available on noncriteria emissions

Continued

T-1448

TABLE 6-13. Continued

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
D (Cont.)	4.1/5.1 (14)/(18)	Watertube	Low Excess Air (2.6)	34	-3	CO	158	+141
						UHC	--	--
						SO_3	--	--
						PART	--	--
	4.1/5.1 (14)/(18)	Watertube	Baseline (30)	54	--	CO	0	--
						UHC	1	--
						SO_3	--	--
						PART	--	
	4.1/5.1 (14)/(18)	Watertube	High Excess Air (HEA) (4.3)	55	+1	CO	0	0
						UHC	3	+2
						SO_3	6	--
						PART	8	--
	4.1/5.1 (14)/(18)	Watertube	Low Excess Air (1.6)	44	-10	CO	60	+60
						UHC	2	+1
						SO_3	--	--
						PART	--	--
	3.5/5.1 (12)/(18)	Watertube	Baseline (4.3)	47	--	CO	0	--
						UHC	--	--
						SO_3	--	--
						PART	9	--
	3.5/5.1 (12)/(18)	Watertube	Low Excess Air (3.7)	46	-1	CO	0	0
						UHC	--	--
						SO_3	--	--
						PART	--	--
E	4.6/5.3 (16)/(20)	Firetube	Baseline (5.8)	126	--	CO	0	--
						UHC	6	--
						SO_3	4	--
						PART	14	--
	4.1/5.8 (14)/(20)	Firetube	Low Excess Air (2.7)	76	-50	CO	0	0
						UHC	17	+11
						SO_3	--	--
						PART	--	--

[a] No data available on noncriteria emissions

Continued

T-1448

TABLE 6-13. Continued

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
F	4.2/5.1 (14)/(18)	Watertube	Baseline (31)	66	--	CO UHC SO_3 PART	3 1 1 25	-- -- -- --
	4.2/5/1 (14)/(18)	Watertube	Low Excess Air (1.2)	55	-11	CO UHC SO_3 PART	62 1 3 15	+59 0 +2 -10
	4.2/5/1 (14)/(18)	Watertube	Flue Gas Recirculation (0.85) (28.4 % FGR)	17	-49	CO UHC SO_3 PART	7 1 5 5	+4 +0 +4 -20
	4.3/5.1 (15)/(18)	Watertube	Flue Gas Recirculation (0.7) (27.9 % FGR)	19	-47	CO UHC SO_3 PART	24 1 -- --	+21 0 -- --
	4.2/5.1 (14)/(18)	Watertube	Overfire Air (3.1)	54	-12	CO UHC SO_3 PART	12 1 1 12	+9 0 0 -13
	4.3/5.1 (15)/(18)	Watertube	Overfire Air (3.2)	55	-11	CO UHC SO_3 PART	8 0 -- --	5 -1 -- --
G	5.0/8.4 (17)/(28)	Watertube	Baseline (5.3)	51	--	CO UHC SO_3 PART	31 -- 12 13	-- -- -- --
	6.0/8.4 (20)/(28)	Watertube	Low Excess Air (4.7)	47	-4	CO UHC SO_3 PART	51 -- -- --	+20 -- -- --

Continued

T-1448

[a] No data available on noncriteria emissions

TABLE 6-13. Concluded

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
H	20/58 (68)/(200)	Watertube	Baseline (4.4)	58	--	CO	0	--
						UHC	0	--
						SO_3	--	--
						PART	12	--
		Watertube	Overfire Air (5.4)	55	-3	CO	0	0
						UHC	0	0
						SO_3	--	--
						PART	--	--

T-1448

[a] No data available on noncriteria emissions

TABLE 6-14. INCREMENTAL EMISSIONS FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
A	4.9/8.4 (17)/(27)	Watertube	Baseline (2.2)	40	--	CO UHC SO_3 Part.	21. -- -- --	-- -- -- --
	7.3/8.4 (24)/21)	Watertube	Low Excess Air (0.9)	38	-2	CO UHC SO_3 Part.	152 -- -- --	+131 -- -- --
B	32/46 (10/(157)	Watertube	Baseline (5.3)	79	--	CO UHC SO_3 Part.	0 22 -- --	-- -- -- --
	35/46 (120)/(157)	Watertube	Low Excess Air (3.2)	82	+3	CO UHC SO_3 Part.	3 12 -- --	+3 -13 -- --
	35/46 (120)/(157)	Watertube	Reduced Air Preheat (5.2)	81	+2	CO UHC SO_3 Part.	0 12 -- --	0 -10 -- --
C	8.4/20 (27)/(70)	Watertube	Baseline (5.7)	108	--	CO UHC SO_3 Part.	0 0 -- --	-- -- -- --
	8.4/20 (27)/(70)	Watertube	Low Excess Air (3.7)	85	-23	CO UHC SO_3 Part.	4 0 -- --	+4 0 -- --
	8.4/20 (27)/(70)	Watertube	Reduced Air Preheat (5.6)	100	-8	CO UHC SO_3 Part.	0 -- -- --	0 -- -- --

[a] No data available on noncriteria emissions

Continued

T-1450

TABLE 6-14. Continued

System				NO_x Emissions		Criteria Emissions[a]		
Boiler Test Series	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
D	22/38 (76)/(130)	Watertube	Baseline (7.1)	82	--	CO UHC SO_3 Part.	62 -- -- --	-- -- -- --
	22/38 (76)/(130)	Watertube	Reduced Air Preheat (7.1)	83	+1	CO UHC SO_3 Part.	70 -- -- --	+12 -- -- --
	24/35 (82)/(120)	Watertube	Baseline (4.4)	117	--	CO UHC SO_3 Part.	0 -- -- --	-- -- -- --
	24/35 (82)/(120)	Watertube	Low Excess Air (2.2)	111	-1	CO UHC SO_3 Part.	0 -- -- --	0 -- -- --
E	57/73 (193)/(250)	Watertube	Baseline (2.6)	96	--	CO UHC SO_3 Part.	100 7 -- --	-- -- -- --
	58/73 (200)/(250)	Watertube	Reduced Air Preheat (2.6)	71	-25	CO UHC SO_3 Part.	112 -- -- --	+12 -- -- --
	58/73 (200)/(250)	Watertube	Reduced Air Preheat (2.5)	95	-1	CO UHC SO_3 Part.	99 -- -- --	-1 -- -- --

[a] No data available on noncriteria emissions

Continued

T-1450

TABLE 6-14. Continued

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
F	12/13 (40)/(45)	Watertube	Baseline (1.9)	112	--	CO UHC SO_3 Part.	0 2 -- --	-- -- -- --
	12/13 (40)/(45)	Watertube	Low Excess Air (1.35)	93	-19	CO UHC SO_3 Part.	279 0 -- --	-279 -2 -- --
	12/13 (40)/(45)	Watertube	Reduced Air Preheat	120	+8	CO UHC SO_3 Part.	9 2 -- --	+9 0 -- --
	10/13 (35)/(45)	Watertube	Reduced Air Preheat	63	-49	CO UHC SO_3 Part.	9 0 -- --	+9 -2 -- --
	11/13 (35)/(45)	Watertube	Overfire Air (3.4)	82	-30	CO UHC SO_3 Part.	6 0 -- --	+6 -- -- --
	11/13 (14)/(18)	Watertube	Overfire Air	52	-60	CO UHC SO_3 Part.	11 -- -- --	+11 -- -- --
G	4.1/5.1 (14)/(18)	Watertube	Baseline (3.2)	30	--	CO UHC SO_3 Part.	3 1 -- --	-- -- -- --

[a] No data available on noncriteria emissions

Continued T-1450

TABLE 6-14. Continued

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
G (Cont.)	4.1/5.1 (14)/(18)	Watertube	Low Excess Air (2.0)	29	-1	CO UHC SO_3 Part.	25 -- -- --	+22 -- -- --
	4.1/5.1 (14)/(18)	Watertube	Flue Gas Recirculation (2.9)	19	-11	CO UHC SO_3 Part.	0 0 -- --	-3 -1 -- --
	3.9/5.1 (13)/(18)	Watertube	Flue Gas Recirculation (2.75)	8	-22	CO UHC SO_3 Part.	37 13 -- --	+34 +12 -- --
	4.2/5.1 (14)/(18)	Watertube	Overfire Air (2.8)	39	+9	CO UHC SO_3 Part.	0 0 -- --	-3 -1 -- --
	4.0/5.1 (14)/(18)	Watertube	Overfire Air (2.4)	27	-3	CO UHC SO_3 Part.	3 0 -- --	0 -1 -- --
H	12/13 (40)/(45)	Watertube	Baseline (1.6)	82	--	CO UHC SO_3 Part.	43 -- -- --	-- -- -- --
	11/13 (40)/(45)	Watertube	Low Excess Air (1.25)	71	-11	CO UHC SO_3 Part.	619 -- -- --	576 -- -- --

[a] No data available on noncriteria emissions

Continued

T-1450

TABLE 6-14. Continued

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
H (Cont.)	11/13 (40)/(45)	Watertube	Overfire Air (2.25)	57	-25	CO UHC SO_3 Part.	38 -- -- --	-5 -- -- --
	12/13 (40)/(45)	Watertube (2.2)	Reduced Air Preheat	62	-20	CO UHC SO_3 Part.	3 -- -- --	-40 --1 -- --
	12/13 (40)/(45)	Watertube	Overfire Air (2.25)	53	-29	CO UHC SO_3 Part.	85 -- -- --	-42 -- -- --
I	4.2/5.1 (14)/(18)	Watertube	Baseline (3.0)	49	--	CO UHC SO_3 Part.	1 1 -- --	-- -- -- --
	4.1/5.1 (14)/(18)	Watertube	Flue Gas Recirculation (3.2) (20.3% FGR)	12	-37	CO UHC SO_3 Part.	6 1 -- --	+5 0 -- --
	4.4/5.1 (14)/(18)	Watertube	Flue Gas Recirculation (2.5) (19.9% FGR)	11	-38	CO UHC SO_3 Part.	5 0 -- --	+4 -1 -- --
	4.0/5.1 (14)/(18)	Watertube	Baseline (3.2)	46	--	CO UHC SO_3 Part.	6 1 -- --	-- -- -- --

[a] No data available on noncriteria emissions

Continued

T-1450

TABLE 6-14. Continued

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
I (Cont.)	4.0/5.1 (14)/(18)	Watertube	Low Excess Air (1.1)	44	-2	CO UHC SO_3 Part.	208 0 -- --	+302 -1 -- --
	4.2/5.1 (14)/(18)	Watertube	Overfire Air (2.8)	25	--	CO UHC SO_3 Part.	91 0 -- --	+85 0 -- --
	4.0/5.1 (14)/(18)	Watertube	Flue Gas Recirculation (3.3)	13	-33	CO UHC SO_3 Part.	5 0 2 3	-1 0 -- -1
J	2.5/3.5 (8.5)/12)	Firetube	Baseline (7.1)	87	--	CO UHC SO_3 Part.	19 -- -- --	-- -- -- --
	2.2/3.5 (7.5)/(12)	Firetube	Low Excess Air (6.6)	90	+3	UHC UHC SO_3 Part.	50 -- -- --	+31 -- -- --
	2.3/3.5 (2.5)/(12)	Firetube	High Excess Air (7.8)	90	+3	CO UHC SO_3 Part.	55 -- -- --	+36 -- -- --
K	5.8/7.3 (20)/(25)	Watertube	Baseline (10.3)	64	--	CO UHC SO_3 Part.	25 -- -- --	-- -- -- --

[a] No data available on noncriteria emissions

Continued

T-1450

TABLE 6-14. Concluded

Boiler Test Series	System			NO$_x$ Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO$_x$ Control (Excess O$_2$, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
K (Cont.)	5.8/7.3 (20)/(25)	Watertube	Low Excess Air	67	+3	CO	27	+2
						UHC	--	--
						SO$_3$	--	--
						Part.	--	--
	5.7/7.3 (20)/(25)	Watertube	Low Excess Air	68	+4	CO	31	+6
						UHC	--	--
						SO$_3$	--	--
						Part.	--	--
	5.7/7.3 (20)/(25)	Watertube	Low Excess Air (6.1)	65	+1	CO	36	+11
						UHC	--	--
						SO$_3$	--	--
						Part.	--	--
	5.6/7.3 (20)/(25)	Watertube	Low Excess Air (5.0)	59	-5	CO	883	+858
						UHC	--	--
						SO$_3$	--	--
						Part.	--	--

[a] No data available on noncriteria emissions

T-1450

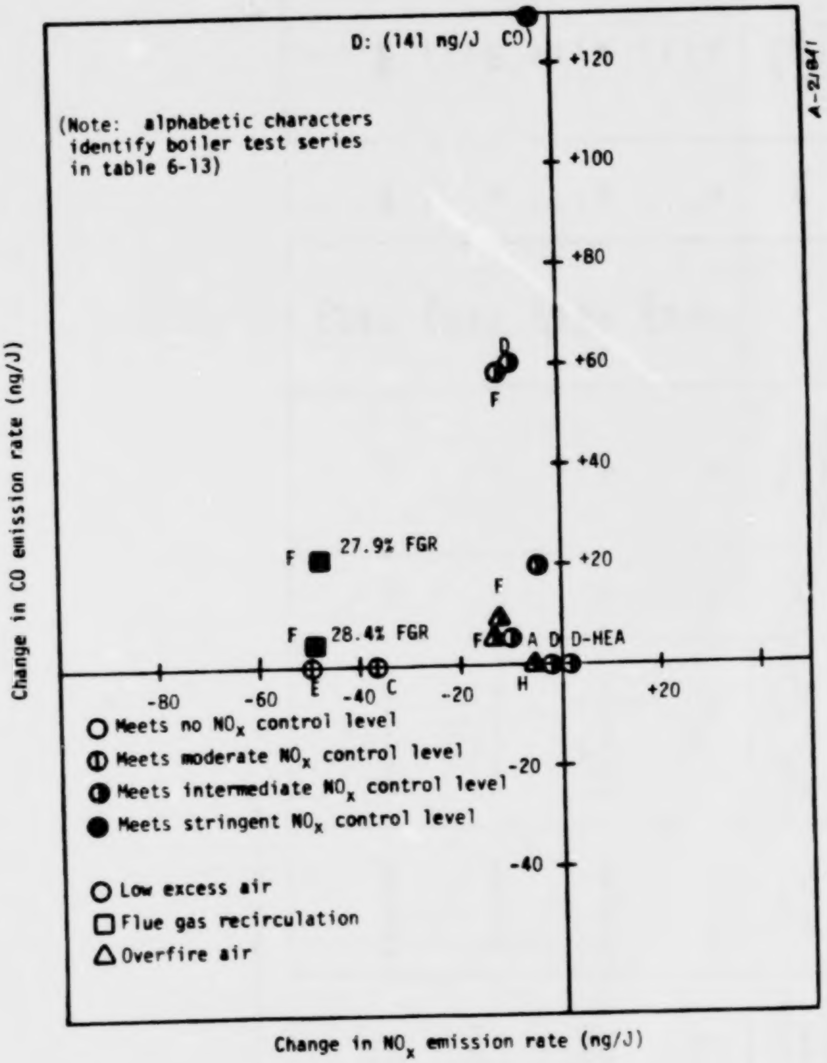


Figure 6-12. Change in CO emission rate with NO$_x$ control for distillate oil-fired industrial boilers (References 6-15 and 6-17).

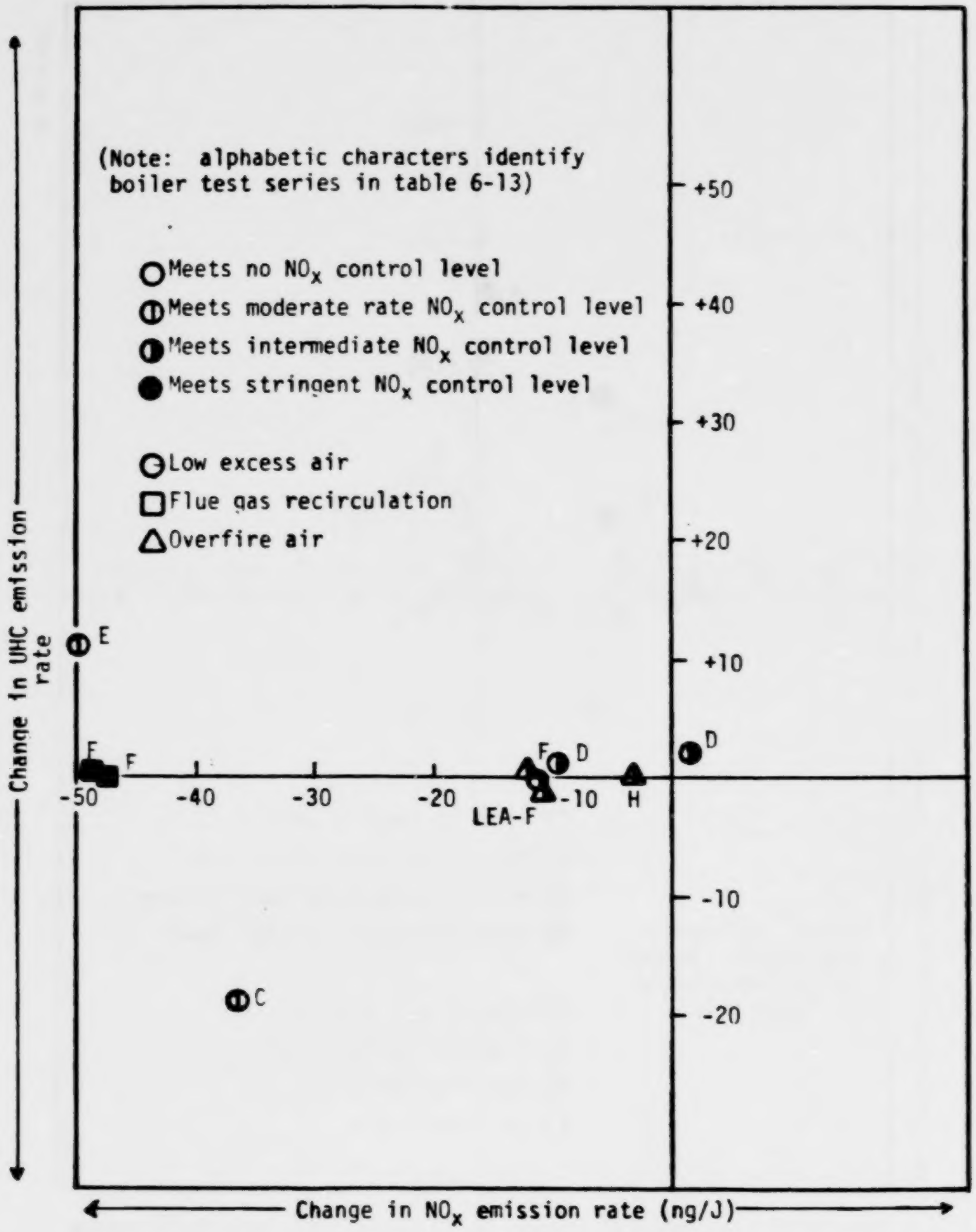
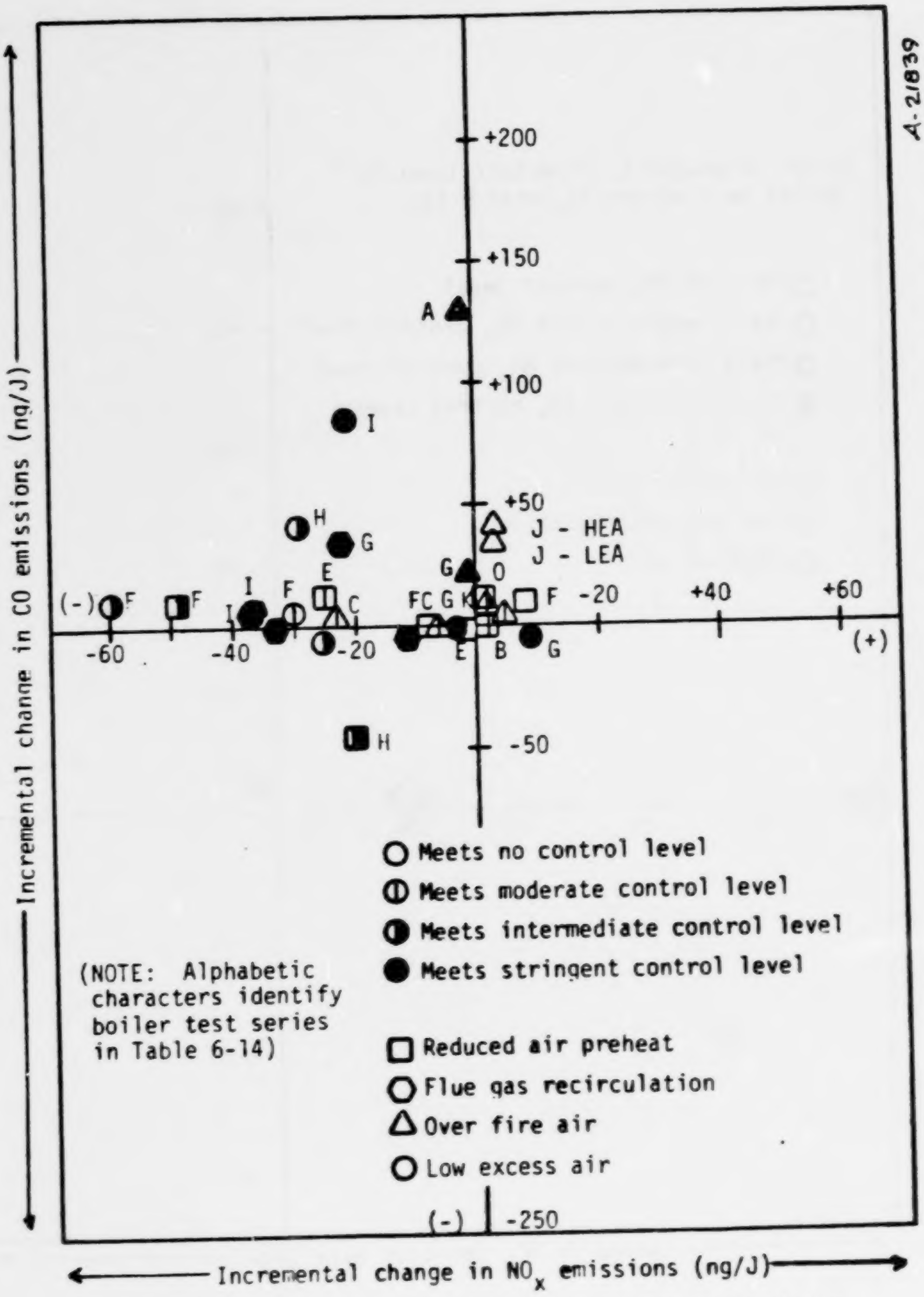


Figure 6-13. Change in UHC emission rate with NO_x control for distillate oil-fired industrial boilers (Reference 6-15 and 6-17).

A-21839



(NOTE: Alphabetic characters identify boiler test series in Table 6-14)

Figure 6-14. Change in CO emissions with NO$_x$ control for a gas-fired industrial boiler (Reference 6-17).

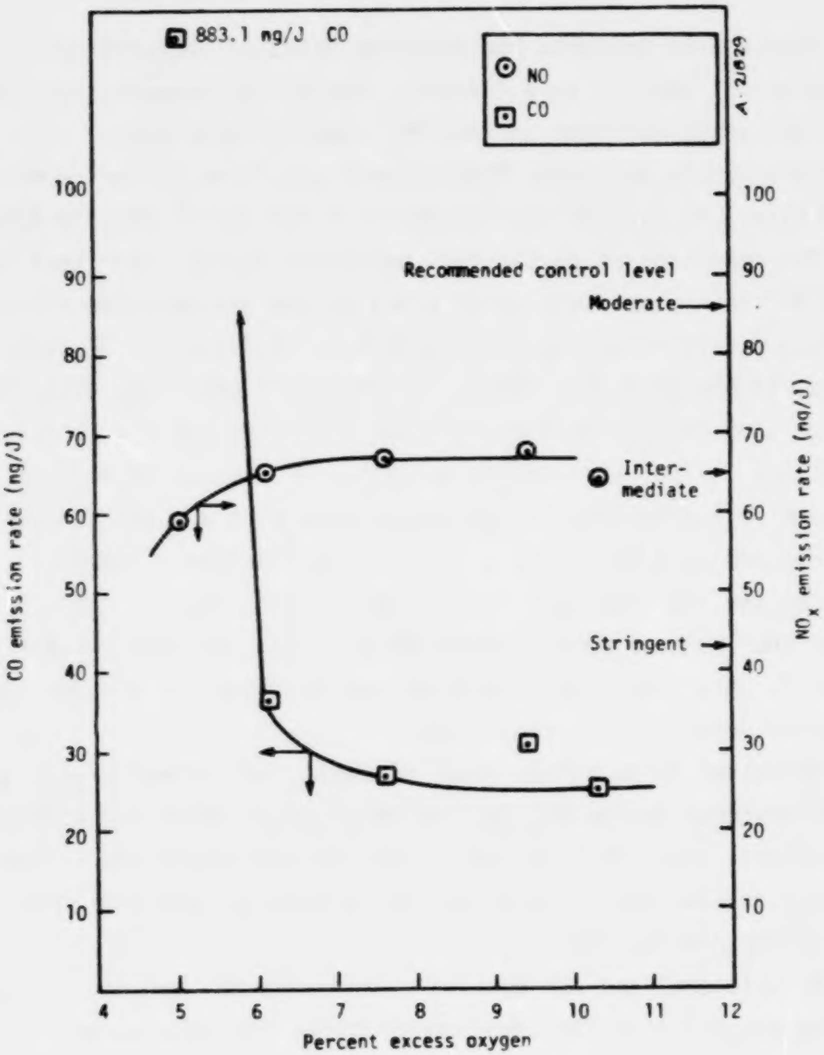


Figure 6-15. Changes in CO and NO$_x$ emissions with reduced excess oxygen for a gas-fired watertube industrial boiler (Reference 6-17).

function of low excess air levels. As with coal and residual oil, a point is reached where CO emissions begin to increase rapidly. It is readily apparent that, with this technique, a small incremental decrease in NO_x results in a large change in CO emissions at the lower excess oxygen levels.

Figure 6-16 presents the emission rates of unburned hydrocarbons. The quantity of data is very limited. Generally, however, very slight changes are noted with the various NO_x control techniques.

Particulate emissions from natural gas-fired boilers were reported as typically 1.72 to 3.01 ng/J (0.004 to 0.007 lb/10^6 Btu) in Reference 6-19. The reporting of particulate emissions during later test work with various NO_x techniques were omitted due to the low emission rates. Distillate oil-fired boilers emitted 8.6 to 17.2 ng/J (0.02 to 0.04 lbs/MBtu) in the same test series. Particulate emissions data (Table 6-13) are plotted in Figure 6-17. Once again, as noted with coal- and residual oil-firing, particulate emissions decrease with NO_x control. Since each of the boilers tested is equipped with a dust control device, this could indicate an increase in particle size under low NO_x conditions and improved dust control device efficiency. Table 6-15 confirms the shift to larger particles with 82.0 percent greater than 1.3 micrometers under baseline conditions and 94.5 percent greater than 1.3 micrometers under low NO_x conditions.

Emissions of sulfates, trace elements, and organics have generally not been measured during NO_x testing programs on units firing distillate oil or natural gas. This is due to the low concentrations of these components in the fuel. Therefore, no incremental emission data is available for presentation.

As with coal and residual oil fuels, low NO_x burners and ammonia injection are still in the development stages for natural gas application. Actual incremental emission data are not available.

6.6 OTHER POLLUTION SOURCES

The above discussions have centered around the impact of NO_x controls on the products of combustion. Generally, the pollutants are emitted from the stack as air pollutants. The decreased particulate emissions from the stack under low NO_x conditions are assumed to result from particulate collection by dust control devices. This increases the

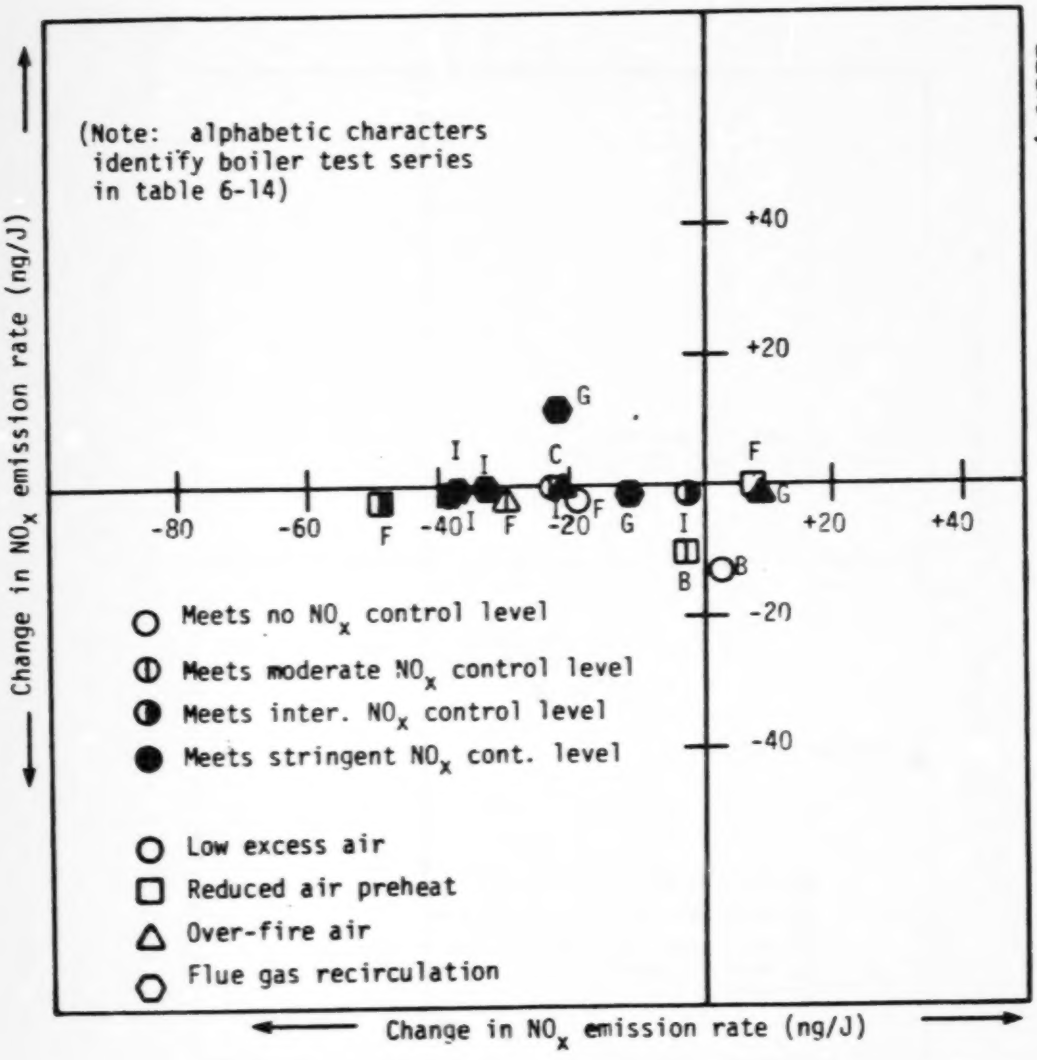


Figure 6-16. Change in unburned hydrocarbon emissions with NO$_x$ control for gas-fired industrial boilers (References 6-15 and 6-17).

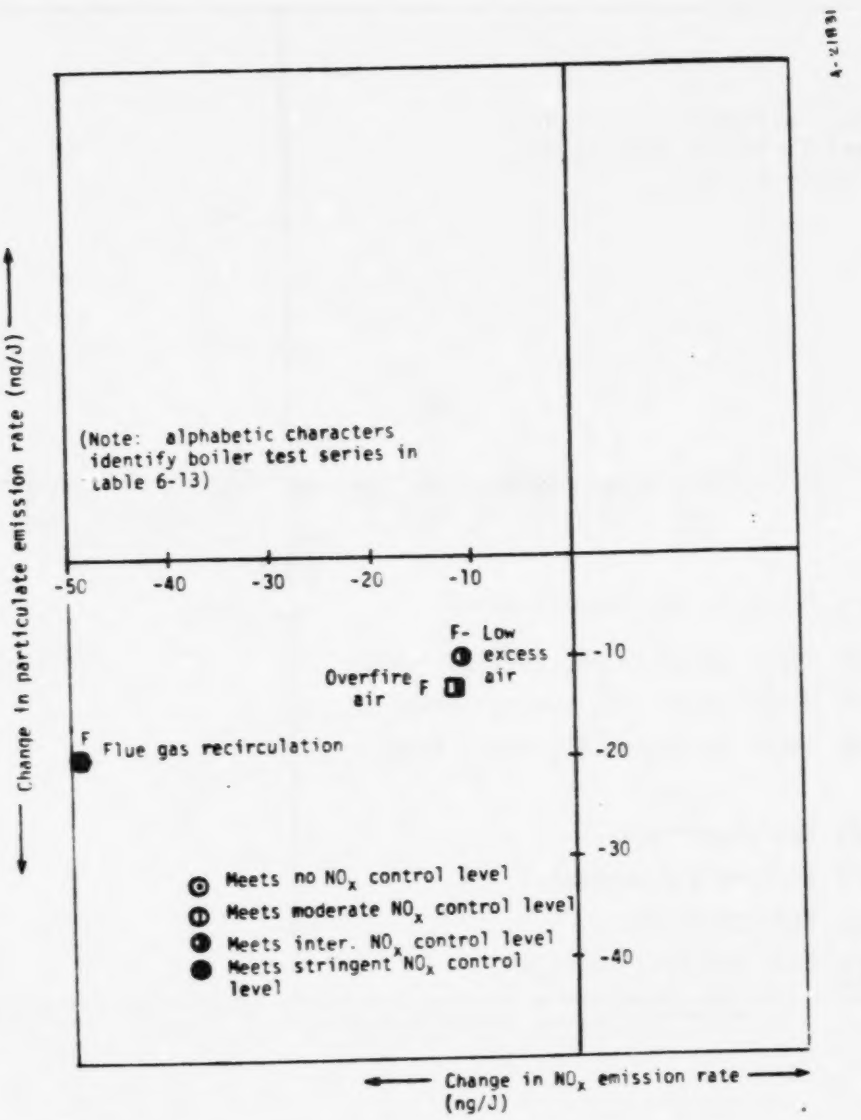


Figure 6-17. Change in particulate emissions with NO$_x$ control for a distillate oil-fired watertube industrial boiler (Reference 6-15).

TABLE 6-15. EFFECT OF OVERFIRE AIR NO_x CONTROL ON PARTICLE SIZE DISTRIBUTION FOR A DISTILLATE OIL-FIRED WATERTUBE INDUSTRIAL BOILER (Reference 6-16)

												Cyclone, Stage and Filter Catch							
						Actual D_{50} of Stage No.[b]						Stage No.							
Fuel Type	Burner Type	Test Load GJ hr^{-1}	NO_x ng/J	Impact Flow cm^3 s^{-1}	D_{50} Cycl. µm	1 µm	2 µm	3 µm	4 µm	5 µm	Cyclone mg	1 mg	2 mg	3 mg	4 mg	5 mg	Filter mg	Total Catch mg	Comments
No. 2	Steam	58	49.4	28.3	--	3.2	1.9	1.3	0.64	0.32	None	96.9	7.55	0.408	0.756	0.008	0.368	105.6	Lower Load
No. 2	Steam	65	--	28.3	--	3.2	1.9	1.3	0.64	0.32	None	5.60	0.148	0.064	1.032	0.024	0.192	7.06	Low NO_x
No. 2	Steam	65	--	28.3	--	3.2	1.9	1.3	0.64	0.32	None	10.6	3.57	0.788	0.62	0.034	0.20	15.842	Baseline

T-1455

[a] Particle size distribution determined by use of a Brink model "B' cascade impactor

[b] D_{50} identifies the size fraction in micrometers. Particulates with an aerodynamic diameter greater than the D_{50} cut point will be captured. Increasing stage number corresponds to decreasing particle size.

quantity of solid waste to be discharged from the system. The incremental increase in solid pollutants is expected to be small when compared to the total dust emissions from the system. No continuous sources of water are involved with the NO_x control techniques. Increased deposits within the boiler not removed as slag may require increased washing of internal surfaces. In addition, dust or slag removal devices which utilize sluicing as the transport mechanism for ash disposal may be increased slightly. However, information is not available to determine if the overall pollutant burden (leachate concentration, chemical oxygen demand, suspended solids content, etc.) would be impacted.

Pollution increases due to thermal and electrical discharge are not expected to increase. Noise pollution would be affected by any increase in operating equipment (such as fans for flue gas recirculation). However, it is not expected that the incremental increase will be measurable when compared to the overall plant noise level.

6.7 SUMMARY

Tables 6-16 through 6-19 compare the recommended NO_x control techniques, the levels of control achievable, and the resulting incremental changes in other pollutant emissions. Where actual data are not available, a postulated effect is presented.

Carbon monoxide levels generally increase with NO_x control, although this can be minimized if not eliminated with judicious application of the control. Actual test data shows unburned hydrocarbon emissions to be decreased more often than increased, though the data are variable. Sulfate emissions decrease with decreasing oxygen content; particulate emissions decrease due to an (assumed) increase in particulate control device collection efficiency. The best NO_x control device for industrial boilers firing coal appear to be low excess air and staged combustion (overfire air), but information is too limited to be conclusive.

Low excess air and staged combustion (overfire air) appears to have little effect on incremental emissions from residual oil-fired boilers. For distillate oil- and natural gas-fired boilers, flue gas recirculation, staged combustion, and reduced air preheat appear to be the best methods available.

Incremental emissions are potentially increased by NO_x controls. More data are needed to quantify the incremental emissions for each control technique and to determine if any significant environmental impact may result.

TABLE 6-16. POSTULATED EFFECT OF CANDIDATE NO_x CONTROL SYSTEMS ON INCREMENTAL EMISSIONS FROM COAL-FIRED INDUSTRIAL BOILERS

Boiler	NO_x Control Technique	Level of Control	Change in Incremental Emissions			
			CO	UHC	SO_3	Particulate
Coal-Fired Boiler ≥29 MW	Low Excess Air	Moderate	+	-	(-)	(-)[a]
		Intermediate	+	-	-	-
		Stringent	+	v	-	-
	Overfire Air	Intermediate	+	(+)	(-)	(-)[a]
		Stringent	+	+	-	(-)[a]
	Low NO_x Burners	Stringent	(+)	(+)	(-)	(-)[a]
	Ammonia Injection[b]	Stringent	(NE)	(NE)	(+)	(NE)
Coal-Fired Boilers < 29 MW	Low Excess Air	Intermediate	-	+	(-)	-
		Stringent	v	(+)	(-)	(-)[a]

T-1453

( ) No data available
- Some decrease
+ Some increase
v Variable results
NE No effect

[a] Assuming dust control devices are utilized, otherwise (+)

[b] Ammonia injection may cause ammonia and byproduct emissions

TABLE 6-17. POSTULATED EFFECT OF CANDIDATE NO_x CONTROL SYSTEMS ON INCREMENTAL EMISSIONS FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS

NO_x Control Technique	Level of Control	Change in Incremental Emissions			
		CO	UHC	SO_3	Particulate
Low Excess Air	Moderate	+	(+)	(-)	-
	Intermediate	+	v	-	-
	Stringent	++	v	-	-
Overfire Air	Moderate	(+)	(+)	(-)	(-)[a]
	Intermediate	+	+	(-)	-
	Stringent	+	+	-	-
Low NO_x Burners	Intermediate	(+)	(+)	(-)	(-)[a]
	Stringent	(+)	(+)	(-)	(-)[a]
Ammonia Injection	Stringent	(NE)	(NE)	(+)	(NE)

( ) No data available
- Some decrease
+ Some increase
++ Significant increase
a Assuming dust control devices are utilized. Otherwise (+)
v Variable results
NE No Effect

TABLE 6-18. POSTULATED EFFECT OF CANDIDATE NO_x CONTROL SYSTEMS ON INCREMENTAL EMISSIONS FROM DISTILLATE OIL-FIRED INDUSTRIAL BOILERS

NO_x Control Technique	Level of Control	Change in Incremental Emissions			
		CO	UHC	SO_3	Particulate
Low Excess Air	Moderate	(+)	(+)	(-)	(-)
	Intermediate	++	-	(-)	(-)[a]
	Stringent	(++)	(+)	(-)	(-)[a]
Flue Gas Recirculation	Moderate	(+)	(+)	(-)	(-)[a]
	Intermediate	(+)	(+)	(-)	(-)[a]
	Stringent	+	+	(-)	(-)[a]
Overfire Air	Moderate	(+)	(+)	(-)	(-)[a]
	Intermediate	+	+	(-)	-
	Stringent	+	+	-	-
Reduced Air Preheat	Intermediate	(NE)	(NE)	(-)	(+)
	Stringent	(NE)	(NE)	(-)	(+)
Low NO_x Burners	Stringent	(+)	(+)	(-)	(-)[a]

( ) No data available
- Some decrease
+ Some increase
++ Significant increase
a Assuming dust control devices are utilized. Otherwise (+)
NE No Effect

TABLE 6-19. POSTULATED EFFECT OF CANDIDATE NO_x CONTROL SYSTEMS ON INCREMENTAL EMISSIONS FROM GAS-FIRED INDUSTRIAL BOILERS

NO_x Control Technique	Level of Control	Change in Incremental Emissions[a]	
		CO	UHC
Low Excess Air	Moderate	+	(+)
	Intermediate	+	-
	Stringent	+	(+)
Flue Gas Recirculation	Moderate	(+)	(+)
	Intermediate	(+)	(+)
	Stringent	-	(+)
Overfire Air	Moderate	+	(+)
	Intermediate	+	(+)
	Stringent	-	-
Reduced Air Preheat	Moderate	+	-
	Intermediate	+	(+)
	Stringent	+	(+)
Low NO_x Burners	Stringent	(+)	(+)

( ) No data available
- Some decrease
+ Some increase
++ Significant increase
a SO_3 and particulate not present in natural gas combustion products

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SECTION 7

EMISSION SOURCE TEST DATA

This section contains the experimental data recorded on tests of various NO_x emission controls conducted on industrial boilers. Data selection and test methods are summarized. These data (References 7-1 through 7-9) were used to generate the baseline and controlled NO_x emission levels presented in the preceding sections of this report.

7.1 CRITERIA FOR SELECTION

A brief description of the data selection procedure follows in Section 7.1.1. Section 7.1.2 summarizes the test methods used.

7.1.1 Data Selection

Where possible, the data selected from published tests had to meet certain prescribed criteria to be included in the NO_x control technology assessment. These criteria included:

- Well planned and controlled experimental conditions in which only the parameter under investigation was allowed to vary. All other important parameters were held as constant as practically possible.
- Characterization and documentation of all major parameters and conditions during the test, such as fuel analysis, and boiler and burner design and operating variables.
- Representative boilers with representative baseline emissions. In some cases, however, very limited data did not permit a determination of representativeness. These cases have been noted in the text of this report.
- Reasonableness of the data. In some cases extreme values are given, as these were the only data available. These values are generally noted and this section contains, in addition to the

parameters associated with these data, other data which support more moderate values, if available.

- Reliability and reproducibility of the data. In many cases, because of the very limited number of tests run, reproducibility could not be confirmed.

In the following data tables in this Section, a few selected test points may involve unacceptable operating conditions, as defined by:

- CO emissions >400 ppm @ 3 percent O_2
- Bacharach smoke spot no. > 4
- Opacity >20 percent

Those controlled test points with high CO and/or smoke emissions are indicated with an asterisk (*) in the data tables. However, it should be pointed out that in most cases, these "special" test points already had baseline NO_x emission levels meeting or exceeding the suggested moderate control level (and in some cases even the stringent control level), all under acceptable operating conditions. And therefore it is not unexpected that further application of combustion modifications may lead to unacceptable operating conditions. Thus these data points are included here, in order for the data base to be complete and to project ranges of extreme control, as observed by field investigators.

7.1.2 Test Methods

The two major investigative groups, KVB and Ultrasystems, used both wet chemical and instrumental methods. For instance, one group (KVB) used EPA Method 5 for particulate matter and EPA Method 9 for opacity. For sulfur oxides they used the Shell-Emeryville wet chemical procedure and for the remaining gases they used instruments obtained from a variety of manufacturers. The other group, Ultrasystems, principally used instrumentation to measure concentration. Selection of the methods used by both companies were primarily based on:

- Portability. All boilers investigated were in the field;
- Cost. Despite their high initial cost, most instruments if properly calibrated and maintained are more cost-effective than the wet analytical methods they replace;
- Reliability. Properly calibrated and maintained instruments are generally far more reliable than the wet methods they replace.

Table 7-1 lists the types of monitors employed by the two principal groups of investigators and their operating principles. A brief synopsis of the errors associated with the measurement of each of the pollutants follows. Only those for NO/NO_x are presented. The reader is referred to Reference 7-4 for a complete discussion of the methods employed.

Nitrogen oxides concentrations were measured by a Thermo Electron model 10A analyzer. The functional basis of the instrument is the chemiluminescent reaction of NO and O_3 to form NO_2 in an excited state. When excited NO_2 molecules revert to their ground state, light emission results. The resulting chemiluminescence is monitored through an optical filter by a high sensitivity photomultiplier tube. The output of the photomultiplier is electronically processed so it is linearly proportional to the NO concentration.

Because the analyzer is sensitive only to NO, total NO_x is determined by reducing any NO_2 in the sample to NO. Reduction is thermal, the gas being passed through a thermally insulated resistance-heated stainless steel coil. NO_2 can be obtained by taking the difference in readings with and without the converter in operation, and assuming that $NO + NO_2 = NO_x$.

The specifications of the instrument are presented below:

Accuracy	1% of full scale
Span stability	± 1% of full scale in 24 hours
Zero stability	± 1 ppm in 24 hours
Power requirements	115 ± 10V, 60 Hz, 1000 watts
Response	90% of full scale in 1 second (NO_x mode), 0.7 sec (NO mode)
Output	4 - 20 ma
Sensitivity	0.5 ppm
Linearity	± 1% of full scale
Vacuum detector operation	
Range	2.5, 10, 25, 100, 250, 1000, 2500, 10,000 ppm full scale

Other criteria pollutants are listed in Table 7-1 along with the instrument or test method used. The reader is referred to Section 6 for a listing of the criteria pollutant emission data associated with NO_x

TABLE 7-1. EMISSION MEASUREMENT INSTRUMENTATION

Emission	Symbol	KVB (References 7-4 and 7-5)		Ultrasystems (Reference 7-2)	
		Measurement Method	Equipment Manufacturer and Model Number	Measurement Method	Equipment Manufacturer and Model Number
Nitric oxide	NO	Chemiluminescent	Thermo Electron 10A	Chemiluminescent	Thermo-Electron[c]
Oxides of nitrogen	NO_x	Chemiluminescent	Thermo Electron 10A	Chemiluminescent	Thermo-Electron[c]
Carbon monoxide	CO	Spectrometer	Beckman 865	Spectrometer	MSA LIRA-303
Carbon dioxide	CO_2	Spectrometer	Beckman 864	--	--
Oxygen	O_2	Polarographic	Teledyne 325A	Polarographic	Theta Sensor[d]
Hydrocarbons	HC	Flame ionization	Beckman 402	--	--
Sulfur dioxide and trioxide	SO_2 SO_3	Absorption/ titration	KVB Equipment Company	Electrochemical[e]	Theta Sensor
Total particulate matter	PM	EPA Method 5	Joy Manufacturing Company	--	--
Particulate size	--	Visual counting Cascade impactor	Millipore Corporation[a] XX50 Monsanto-Brink[b]	--	--
Smoke spot	K	Reflectance Photometric	Research Applicance Company G2R-100	Visual	Bacharach
Opacity	--	EPA Method 9	--	--	--

T-1611

[a] Reference 7-4.
[b] References 7-3, 7-5.
[c] Backup measurements made with Theta Sensor US-6000 analyzer.
[d] Backup measurements made with Teledyne 320AX.
[e] SO_2 only.

controls, and to References 7-2 and 7-4 for a discussion of the instruments and/or techniques employed.

7.2 EMISSION SOURCE TEST DATA FOR COAL-FIRED BOILERS

Coal-fired industrial boilers have been tested during several EPA sponsored field investigations (References 7-4, 7-5 and 7-7 through 7-9). These include six pulverized coal-fired units, one cyclone, twelve spreader stokers, two underfeed stokers, two chain grate stokers and a vibrating grate stoker. Tables 7-2 through 7-4 present the results of NO_x emission controls as applied to pulverized coal and cyclone boilers; Tables 7-5 through 7-8 present the results for various stokers.

The measurement of nitrogen oxides and the errors associated with these measurements have been described in Section 7.1. The direct experimental readings were in parts per million. These were corrected to the nominal 3 percent oxygen level and further corrected for water. The results were then converted into an input specific value, ng/J or lb/10^6 Btu by:

a. Knowing the higher heating value (HHV) of the fuel and the amount of fuel consumed in a given period of time, or
b. Knowing the size of the boiler (the number of pounds of steam produced in a given period of time and the exact relationship between this with the HHV of the fuel, i.e., boiler efficiency).

As fuel consumption was not well documented, the unit conversion constants used by the investigators (References 7-4 and 7-5) were based on (b) from which they obtained a constant for each type of fuel for the conversion.

7.3 EMISSION SOURCE TEST DATA FOR OIL-FIRED INDUSTRIAL BOILERS

Tables 7-9 through 7-15 summarize the results of various NO_x emission controls as applied to a series of boilers burning residual oil. The data were obtained from a large number of tests run on industrial boilers under various EPA programs (References 7-1 through 7-6). The criteria used for selecting these data are listed in Section 7.1.

Residual oils employed in these tests consisted of No. 5 and No. 6 fuel oil and two others, NSF oil and PS 300 oil, which both qualify on the basis of viscosity as No. 5 oils. In addition to the effects of low excess air on boilers burning residual oil, Table 7-9 shows the effects of two differing No. 6 oils on the NO_x emissions of a watertube industrial

TABLE 7-2. NO_x EMISSION TEST DATA FROM PULVERIZED COAL-FIRED INDUSTRIAL BOILERS WITH LOW EXCESS AIR (LEA)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
53.5/65.9 (182)/(225)	LEA[e] 5.3-4.5	26.57[f] (11,430)	1.40	4.20	9.36	1	234 (0.544)	--	--	222 (0.517)	5	Intermediate	# 12-24, T[g], WT[h]	--	7-1
76.2/93.8 (260)/(320)	LEA 5.8-4.8	25.94 (11,160)	1.34	2.74	11.58	1	296 (0.688)	--	--	303 (0.704)	-2	--	# 12-20, T, WT	--	7-1
38.1/76.2 (130)/(260)	LEA 7.4-6.6	27.58 (11,863)	0.83	1.15	10.5	1	563 (1.31)	--	--	529* (1.23)	6	--	# 31-7, SW, WT	--	7-1
117/147 (400)/(500)	LEA 8.6-8.1	28.59 (12,300)	1.50	1.36	14.48	1	216 (0.502)	--	--	212 (0.493)	2	Stringent	# 13-2, SW, WT	Multifuel Furnace	7-1
38.0/67.2 (130)/(230)	LEA 4.5-3.4	21.70 (9,336)	0.73	0.81	10.04	1	201[i] (0.467)	--	--	152[i] (0.353)	25	Stringent	Alma #3, SW, WT	--	7-7
38.0/67.2 (130)/(230)	LEA 6.1-4.0	25.04 (10,776)	1.09	3.68	14.49	1	244[i] (0.567)	--	--	197[i] (0.458)	19	Stringent	Alma #3, SW, WT	--	7-7
32.8/46.7 (112)/(160)	LEA 5.1-3.4	24.9 (10,741)	0.93	0.32	6.89	1	174[i] (0.401)	--	--	136[i] (0.316)	22	Stringent	Fremont #6 SW, WT	--	7-7
93.8/117 (320)/(400)	LEA 3.4-3.1	30.66 (13,190)	1.55	2.92	7.78	1	494 (1.15)	--	--	470 (1.09)	5	--	#20-42, Cy. WT		7-1

T-1575

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Excess oxygen, %, first value is high excess air (baseline) condition, second value is low excess air condition.
[f] MJ/kg (Btu/lb) as received.
[g] T, tangential; SW, single wall; Cy, cyclone
[h] WT, watertube.
[i] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).
* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-3. NO$_x$ EMISSION TEST DATA FROM PULVERIZED COAL-FIRED INDUSTRIAL BOILERS WITH BURNERS-OUT-OF-SERVICE (BOOS)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO$_x$ Emissions[b] ng NO$_2$/J (lb NO$_2$/10^6 Btu)	Controlled NO$_x$ Emissions[h] ng NO$_2$/J (lb NO$_2$/10^6 Btu)			Percent NO$_x$ Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
18.8/76.2 (64)/(260)	BOOS,[e]	27.58[f] (11,863)	0.83	1.15	10.5	1	618 (1.44)	--	--	378* (0.88)	39	--	# 31-7, SW,[g] WT[h]	Only 32% NO$_x$ reduction when compared to baseline at 50% load	7-1
38.1/67.2 (130)/(230)	BOOS,[i]	25.04 (10.776)	1.09	3.68	14.49	1	197 (0.458)	--	--	144 (0.335)	27	Stringent	Alma #3 SW, WT	4% excess O$_2$	7-7

T-1576 T-1576

[a] All reported tests were short-term (<3 hr).
[b] NO$_x$ emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Burner pattern 2 X 2, top row firing air only.
[f] MJ/kg (Btu/lb) as received.
[g] SW, single wall.
[h] WT, watertube.
[i] Burner pattern 2 X 2, top right firing air only.
[j] Estimate only, NO$_x$ values assume NO$_2$ is 5% of total (only NO was measured).
* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-4. NO_x EMISSION TEST DATA FROM PULVERIZED COAL-FIRED INDUSTRIAL BOILERS WITH LOAD REDUCTION (LR)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[h] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
--/93.8 --/(320)	LR[e] 94-62	25.94[f] (11,160)	1.34	2.74	11.58	1	209 (0.486)	--	--	144 (0.335)	31	Stringent	# 12-20, T9, WT9	4% excess O_2	7-1
--/147 --/(500)	LR 92-64	28.59 (12,300)	1.50	1.36	14.48	1	233 (0.541)	--	--	197* (0.458)	15	Stringent	# 13-2, SW, WT	9% excess O_2	7-1
--/76.2 --/(260)	LR 50-25.4	27.58 (11,863)	0.83	1.15	10.5	1	592 (1.38)	--	--	618 (1.44)	-4	--	# 31-7, SW, WT	7% excess O_2	7-1
--/117 --/(400)	LR 100-60	30.66 (13,190)	1.55	2.92	7.78	1	489 (1.14)	--	--	459 (1.07)	6	--	# 20-42, WT	Cyclone 3% excess O_2	7-1
--/672 -/(230)	LR 87-57	25.04 (10,776)	1.09	3.68	14.49	1	246[i] (0.573)	--	--	197[i] (0.458)	20	Stringent	Alma #3 SW, WT	4% excess O_2	7-7
--/672 -/(230)	LR 74-41	21.70 (9,336)	0.73	0.81	10.04	1	283[i] (0.659)	--	--	157[i] (0.365)	45	Stringent	Alma #3 SW, WT	5% excess O_2	7-7
--/46.9 -/(160)	LR[e] 83-41	25.3 (10,889)	1.25	1.48	9.19	1	264[i] (0.613)	--	--	184[i] (0.428)	30	Stringent	Fremont #6 SW, WT	5.4% excess O_2	7-7
--/46.9 -/(160)	LR 72-44	24.9 (10,741)	0.93	0.32	6.89	1	155[i] (0.360)	--	--	158[i] (0.367)	-2	Stringent	Fremont #6 SW, WT	4.2% excess O_2	7-7

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Percent rated load, first value is high load (baseline); second value is low load.
[f] MJ/kg (Btu/lb) as received.
[g] SW, single wall.
[h] WT, watertube.
[i] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).
* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

T-1577

TABLE 7-5. NO_x EMISSION TEST DATA FROM COAL-FIRED INDUSTRIAL STOKERS WITH LOW EXCESS AIR (LEA)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
32.2/39.6 (110)/(135)	LEA[e] 6.5-5.3	29.50[f] (12,690)	1.40	2.94	4.77	1	235 (0.547)	--	--	216 (0.502)	8	Intermediate	# 11-1, SS[g]		7-1
22/39.6 (75)/(135)	LEA 9.0-6.5	29.50 (12,690)	1.40	2.94	4.77	1	263 (0.612)	--	--	219 (0.510)	17	Intermediate	# 11-1, SS	Low Load	7-1
35.2/44.0 (120)/(150)	LEA 10.3-8.9	30.47 (13,110)	1.33	1.58	7.99	1	336 (0.781)	--	--	287 (0.668)	15	Moderate	# 14-1, SS		7-1
44.2/58.6 (151)/(200)	LEA 10.6-8.9	30.96 (13,320)	1.80	0.86	10.36	1	330 (0.767)	--	--	219 (0.509)	34	Intermediate	# 14-4, SS		7-1
11.7/14.6 (40)/(50)	LEA 8.0-5.8	31.96 (13,750)	1.45	0.76	6.75	1	284 (0.660)	--	--	202 (0.469)	29	Moderate	# 21-2, SS		7-1
17.9/22 (61)/(75)	LEA 7.8-5.5	32.08 (13,800)	1.43	1.55	6.94	1	283 (0.658)	--	--	219 (0.509)	22	--	# 21-3, SS		7-1
24.0/36.6 (82)/(125)	LEA 6.2-4.7	30.06 (12,293)	1.46	1.16	9.71	1	196 (0.456)	--	--	142* (0.330)	28	Stringent	# 30-8, SS		7-1
51.9/87.9 (177)/(300)	LEA 4.3-2.7	25.35 (10,365)	1.01	1.05	7.00	1	239[h] (0.556)	--		180[h] (0.419)	25	Stringent	Site A, SS		7-8
59.8/87.9 (204)/(300)	LEA 5.2-3.4	25.89 (10,588)	--	--	5.21	1	293[h] (0.681)	--	--	215[h]* (0.500)	27	Stringent	Site A, SS		7-8
52.7/58.6 (180)/(200)	LEA 7.0-3.2	31.31 (13,469)	1.38	0.81	7.48	1	209[h] (0.036)	--	--	131[h] (0.305)	37	Stringent	Site B, SS		7-9
17.6/29.3 (60)/(100)	LEA 10.9-6.5	20.2 (8,704)	0.78	0.73	8.29	1	312[h] (0.726)	--	--	206[h] (0.479)	34	Stringent	UW-Madison # 2, SS		7-7

Continued

T-1578

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent level discussed in Section 3.
[e] Excess oxygen, %, first value is high excess air (baseline) condition, second value is low excess air condition.
[f] MJ/kg (Btu/lb) as received.
[g] SS, spreader stoker; UFS, underfeed stoker; CGS, chain grate stoker; VGS, vibrating grate stoker.
[h] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).
* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-5. Concluded

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[h] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average				
17.6/29.3 (60)/(100)	LEA[e] 10.0-7.8	27.9[f] (12,006)	1.30	3.07	9.60	1	289[h] (0.672)	--	--	258[h] (0.600)	11	Intermediate	UW-Madison # 2, SS[g]	7-7
23.7/46.9 (81)/(160)	LEA 8.6-7.7	19.5[f] (8,408)	0.68	1.15	9.12	1	236[h] (0.549)	--	--	183[h] (0.426)	22	Stringent	Willmar #3 SS	7-7
31.6/46.9 (108)/(160)	LEA 8.6-6.6	28.9 (12,448)	1.37	2.28	7.76	1	287[h] (0.667)	--	--	241[h] (0.560)	16	Intermediate	Willmar #3 SS	7-7
13.5/23.4 (46)/(80)	LEA 9.4-8.0	25.2 (10,842)	0.48	1.59	7.68	1	207[h] (0.481)	--	--	239[h] (0.556)	-13	--	Fairmont #3 SS	7-7
13.2/17.6 (45)/(60)	LEA 6.6-4.9	26.99 (11,610)	1.40	0.86	9.51	1	163 (0.379)	--	--	117 (0.272)	28	Stringent	# 15-32-10, UFS	7-1
13.5/17.6 (46)/(60)	LEA 9.8-8.0	26.99 (11,610)	1.40	0.86	9.51	1	136 (0.317)	--	--	161 (0.375)	-18	Intermediate	# 15-32-13, UFS	7-1
31.4/63.0 (107)/(215)	LEA 9.5-8.2	27.60 (11,873)	0.94	3.05	13.7	1	100 (0.233)	--	--	96.5* (0.225)	4	Stringent	# 35-6, CGS	7-1
5.0/13.2 (17)/(45)	LEA 9.8-7.3	24.1 (10.378)	0.91	0.83	3.92	1	123[h] (0.290)	--	--	115[h] (0.267)	6	Intermediate	UW Stout # 2, VGS	7-7

T-1578

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Excess oxygen, %, first value is high excess air (baseline) condition, second value is low excess air condition.
[f] MJ/kg (Btu/lb) as received.
[g] SS, spreader stoker, UFS, underfeed stoker; CGS, chain grate stoker; VGS, vibrating grate stoker.
[h] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).
* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-6. NO_x EMISSION TEST DATA FROM COAL-FIRED INDUSTRIAL STOKERS WITH OVERFIRE AIR (OFA)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
24/36.6 (82)/(125)	OFA	30.06[e] (12,293)	1.46	1.16	9.71	2	196* (0.455)	180 (0.419)	195 0.453)	188* (0.436)	4	Stringent	# 30-8, SS[f]	All tests conducted at 6% excess O_2	7-1
24/36.6 (82)/(125)	OFA	30.06 (12,293)	1.46	1.16	9.71	1	196* (0.455)	--	--	145* (0.337)	26	Stringent	# 30-8, SS	OFA ports plus redundant gas jets	7-1
30.5/63.0 (104)/(215)	OFA	27.60 (11,873)	0.94	3.05	13.7	2	100* (0.233)	91.6 (0.213)	101 (0.236)	96.5* (0.225)	4	Stringent	# 35-6, CGS	9% excess O_2	7-1
28/63.0 (95)/(215)	OFA	27.60 (11,873)	0.94	3.05	13.7	2	89.8* (0.209)	96.5 (0.225)	106 (0.247)	101* (0.235)	-13	Stringent	# 35-6, CGS	10% excess O_2	7-1
44.0/58.6 (150)/(200)	OFA	30.96 (13,320)	1.80	0.86	10.36	4	330 (0.767)	177 (0.411)	234 (0.544)	215 (0.499)	35	Stringent	# 14-4, SS	11% excess O_2	7-1
66.2/87.9 (226)/(300)	OFA	23.92 (10,289)	0.95	0.36	7.88	1	254 (0.591)	--	--	227 (0.528)	10	Stringent	Site A, SS	6% excess O_2	7-8
30.8/46.9 (105)/(160)	OFA	19.5 (8,408)	0.68	1.15	9.12	1	236[g] (0.549)	--	--	233[g] (0.542)	1	Intermediate	Willmar #3 SS	9% excess O_2	7-7

T-1579

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] MJ/kg (Btu/lb) as received.
[f] SS, spreader stoker, UFS, underfeed stoker; CGS, chain grate stoker; VGS, vibrating grate stoker.
[g] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).
* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-7. NO_x EMISSION TEST DATA FROM COAL-FIRED INDUSTRIAL STOKERS WITH LOAD REDUCTION (LR)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
--/44.0 --/(150)	LR[e] 100-80	30.47[f] (13,110)	1.33	1.58	7.99	1	346 (0.806)	--	--	338 (0.786)	2	--	# 14-1, SS[g]	9.5 % excess O_2	7-1
--/58.6 --/(200)	LR 100-80	30.96 (13,320)	1.80	0.86	10.36	1	365 (0.850)	--	--	331 (0.770)	9	--	# 14-4, SS	10.8 % excess O_2	7-1
--/58.6 --/(200)	LR 78-50	30.96 (13,320)	1.80	0.86	10.36	1	386 (0.897)	--	--	282 (0.655)	27	Moderate	# 14-4, SS	13% excess O_2	7-1
--/36.6 --/(125)	LR 65.6-38.4	30.06 (12,293)	1.46	1.16	9.71	1	196 (0.455)	--	--	119 (0.277)	39	Stringent	# 30-8, SS	6.2-7.4% excess O_2	7-1
--/29.3 --/(100)	LR 90-60	20.2 (8,704)	0.78	0.73	8.29	1	274[h] (0.636)	--	--	219[h] (0.509)	20	Intermediate	UW-Madison # 2, SS	7.75-7.9% excess O_2	7-7
--/29.3 --/(100)	LR 90-60	27.9 (12,006)	1.30	3.07	9.60	1	325[h] (0.756)	--	--	289[h] (0.673)	11	Moderate	UW-Madison # 2, SS	10.0-10.3% excess O_2	7-7
--/87.9 --/(300)	LR 77-59	24.5 (10,547)	1.01	1.05	6.09	1	213[h] (0.748)	--	--	229[h] (6.533)	29	Moderate	Site A, SS	5.1-5.2% excess O_2	7-8
--/46.9 --/(160)	LR 70-47.6	28.9 (12,448)	1.37	2.28	7.76	1	331[h] (0.769)	--	--	219[h] (0.509)	34	Intermediate	Willmar #3 SS	8.4% excess O_2	7-7
--/46.9 --/(160)	LR 67-49	19.5 (8,408)	0.68	1.15	9.12	1	234[h] (0.543)	--	--	183[h] (0.426)	22	Stringent	Willmar # 3 SS	7.8% excess O_2	7-7
--/23.4 --/(80)	LR 73.5-61	28.8 (12,441)	1.35	2.51	8.24	1	201[h] (0.468)	--	--	171[h] (0.397)	15	Intermediate	Fairmont # 3 SS	8.1% excess O_2	7-7
--/23.4 --/(80)	LR 76-57.5	25.2 (10,842)	0.48	1.59	7.68	1	227[h] (0.529)	--	--	239[h] (0.556)	-5	--	Fairmont # 3 SS	8.0% excess O_2	7-7
--/4.0 --/(13.5)	LR 64.4-42.3	24.5 (10,515)	0.81	0.61	5.14	1	181[h] (0.421)	--	--	128[h] (0.299)	29	Stringent	St. Johns # 2 SS	15.2% excess O_2	7-7

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Percent load; first value is high load (baseline), second value is low load.
[f] MJ/kg (Btu/lb) as received.
[g] SS, spreader stoker, UFS, underfeed stoker; CGS, chain grate stoker; VGS, vibrating grate stoker.
[h] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).

Continued

T-1580

TABLE 7-7. Concluded

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
--/4.0 --/(13.5)	LR[e] 67-41.5	30.5[f] (13,123)	0.95	0.58	5.29	1	265[h] (0.617)	--	--	196[h*] (0.455)	26	Moderate	St. Johns # 2 SS[g]	15.5% excess O_2	7-7
--/17.6 --/(60)	LR 100-78	26.99 (11,610)	1.40	0.86	9.51	1	195 (0.453)	--	--	181 (0.421)	7	Moderate	# 15 32-10, UFS	6% excess O_2	7-1
--/17.6 --/(60)	LR 78-53	26.99 (11,610)	1.40	0.86	9.51	1	181 (0.421)	--	--	114* (0.264)	37	Stringent	# 15-32 11, UFS	10.5% excess O_2	7-1
--/63.0 --/(215)	LR 56-44	27.60 (11,873)	0.94	3.05	13.7	1	94.7 (0.220)	--	--	79.4* (0.185)	16	Stringent	# 35-6, CGS	8.3% excess O_2	7-1
--/63.0 --/(215)	LR 49-37	27.60 (11,873)	0.94	3.05	13.7	1	94.1 (0.219)	--	--	118 (0.274)	-25	Stringent	# 35-6, CGS	11% excess O_2	7-1
--/17.6 --/(60)	LR 58-25	21.5 (9,276)	1.10	0.72	5.1	2	187[h] (0.435)	94.5[h] (0.220)	97.1[h] (0.226)	95.8[h] (0.223)	49	Stringent	UW-Eau Claire # 1, CGS	10.6% excess O_2	7-7
--/17.6 --/(60)	LR 45-25	28.8 (12,382)	1.24	2.79	8.03	2	184[h] (0.428)	128[h] (0.299)	147[h] (0.341)	138[h] (0.321)	25	Intermediate	UW-Eau Claire # 1, CGS	Baseline load at 10.9% excess O_2 Reduced load at 8% excess O_2	7-7
--/13.2 --/(45)	LR 67-26	23.6 (10,142)	0.91	0.83	3.92	1	101[h*] (0.235)	--	--	126[h] (0.293)	-25	Stringent	UW-Stout # 2 VGS	7.8-7.9% excess O_2	7-7
--/13.2 --/(45)	LR 67-44	28.0 (12,023)	1.28	2.81	7.25	1	120[h] (0.279)	--	--	120[h] (0.279)	0	Stringent	UW-Stout # 2 VGS	8.2% excess O_2	7-7

T-1580

[a] All reported tests were short-term (<3 hr).

[b] NO_x emissions determined by chemiluminescence in all cases.

[c] Based on average of all tests.

[d] Moderate, intermediate or stringent levels discussed in Section 3.

[e] Percent load, first value is high load (baseline), second value is low load.

[f] MJ/kg (Btu/lb) as received.

[g] SS, spreader stoker; UFS, underfeed stoker; CGS, chain grate stoker; VGS, vibrating grate stoker.

[h] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).

* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-8. NO_x EMISSION TEST DATA FROM COAL-FIRED INDUSTRIAL STOKERS WITH REDUCED AIR PREHEAT (RAP)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests^a	Baseline NO_x Emissions^b ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions^b ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction^c	Control Level Supported^d	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
24/36.6 (82)/(125)	RAP^e 366.5-354.3	30.06^f (12,293)	1.46	1.16	9.71	1	196 (0.455)	--	--	162* (0.377)	17	Stringent	# 30-8, SS^g	6% excess O_2
24.2/36.6 (82.5)/(125)	RAP 369.4-355.4	30.06 (12,293)	1.46	1.16	9.71	1	132 (0.307)	--	--	134* (0.311)	-2	Stringent	# 30-8, SS	5% excess O_2

T-1501

[a] All reported tests were short-term (<3 hr).

[b] NO_x emissions determined by chemiluminescence in all cases.

[c] Based on average of all tests.

[d] Moderate, intermediate or stringent levels discussed in Section 3.

[e] First value, temperature (K) of baseline combustion air; second value, temperature (K) of RAP combustion air.

[f] MJ/kg (Btu/lb) as received.

[g] SS, spreader stoker.

* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-9. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH LOW EXCESS AIR (LEA)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
2.0/2.1 (6.7)/(7)	LEA[e] 5.4-3.9	42.49[f] (18,280)	0.27	1.85	0.038	1	170 (0.395)	--	--	143 (0.333)	16	--	# 23-1, FT[g]	No. 6 oil	7-1
3.2/3.1 (10.9)/(10.5)	LEA 3.2-1.9	43.61 (18,760)	0.20	1.30	0.26	1	104 (0.243)	--	--	99.3* (0 .231)	5	Intermediate	# 24-TV, FT	No. 5 oil	7-1
5.1/5.3 (17.4)/(18)	LEA 7.2-3.7	42.31 (18,200)	0.10	1.46	0.007	2	95.4 (0.222)	88.1 (0.205)	105 (0.244)	96.5 (0.224)	-1	Intermediate	# 26-1, FT	No. 5 oil	7-1
3.5/3.2 (11.9)/(11)	LEA 4.1-3.7	42.31 (18,200)	0.10	1.46	0.007	1	106 (0.245)	--	--	106* (0.245)	0	Intermediate	# 26-2, FT	No. 5 oil	7-1
1.6/3.5 (5.5)/(12)	LEA 6.1-2.0	--	--	--	--	1	117 (0.273)	--	--	95.9 (0.223)	18	Intermediate	# ECCC, FT	No. 5 oil	7-2
2.3/3.5 (7.9)/(12)	LEA 5.9-3.2	--	--	--	--	1	116 (0.270)	--	--	99.3 (0.231)	14	Intermediate	# ECCC, FT	No 5 oil Higher load	7-2
4.2/5.1 (14.2)/(17.5)	LEA 4.0-2.2	42.49 (18,280)	0.44	2.80	0.044	2	195 (0.454)	155 (0.360)	160 (0.373)	158 (0.367)	19	--	# 19-1, WT	No. 6 oil	7-1
4.1/5.1 (14.1)/(17.5)	LEA 3.1-0.9	45.01 (19,365)	0.14	0.37	0.009	1	94.8 (0.220)	--	--	69.6* (0.162)	27	Stringent	# 19-1, WT	Different No. 6 oil	7-1
15/23 (51)/(80)	LEA 5.7-4.0	43.00 (18,500)	0.37	1.49	0.019	1	174 (0.404)	--	--	155 (0.361)	11	--	# 20-4, WT	No. 6 oil	7-1
10.5/13.2 (36)/(45)	LEA 3.0-1.6	44.69 (19,227)	0.49	0.19	0.08	1	183 (0.426)	--	--	136 (0.317)	26	--	# 38-2, WT	No. 6 oil	7-1
5.7/7.3 (19.5)/(25)	LEA 5.5-3.6	--	--	--	--	1	87.5 (0.203)	--	--	63.4 (0.147)	28	Stringent	# ECCC, WT	No. 5 oil	7-2
3.7/5.6 (12.5)/(19.2)	LEA[e] 7.6-7.1	43.54[f] (18.730)	0.26	1.59	0.065	1	112 (0.260)	--	--	105 (0.244)	6	Intermediate	# 15-123-1, WT[g]	NSF oil (No. 5 oil)	7-1

[a] All reported tests were short-term (3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] First value, temperature (K) of baseline combustion air; second value, temperature (K) of RAP combustion air.
[f] MJ/kg (Btu/lb).
[g] FT, firetube; WT, watertube.
* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

T-1581

Continued

TABLE 7-9. Concluded

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
29.3/36.6 (100)/(125)	LEA 6.4-4.6	--	0.52	1.15	0.026	1	189 (0.440)	--	--	178 (0.414)	6	--	# 2-6, WT	PS 300 oil (No. 5 oil)	7-1
24.3/29.3 (83)/(100)	LEA 9.3-5.9	42.62 (18,333)	0.77	1.29	0.10	1	257 (0.598)	--	--	225 (0.523)	12	--	# 27-1, WT	PS 300 oil (No. 5 oil)	7-1
15.2/19.0 (52)/(65)	LEA 4.7-3.6	44.0 (18,930)	0.29	1.03	0.043	1	106 (0.247)	--	--	105 (0.244)	1	Intermediate	# 16-2, WT	No. 6 oil	7-1
21.1/26.4 (72)/(90)	LEA 7.4-7.0	42.82 (18,420)	0.26	1.04	0.031	1	138 (0.321)	--	--	121 (0.282)	12	Moderate	# 18-2, WT	No. 6 oil	7-1
23.4/30.8 (80)/(105)	LEA 6.3-5.3	43.96 (18,910)	0.26	1.03	0.032	1	142 (0.330)	--	--	116 (0.269)	18	Moderate	# 18-3, WT	No. 6 oil	7-1
34.9/46.9 (119)/(160)	LEA 7.2-6.0	43.96 (18,910)	0.26	1.03	0.032	1	133 (0.309)	--	--	131 (0.304)	2	--	# 18-4, WT	No. 6 oil	7-1
8.5/20.5 (29)/(70)	LEA 5.3-4.9	--	--	--	--	1	115 (0.267)	--	--	101* (0.235)	12	Intermediate	# 28-1, WT	No. 6 oil	7-1
35.5/44.0 (121)/(150)	LEA 5.0-3.1	42.34 (18,213)	0.31	2.74	0.03	1	66.8 (0.155)	--	--	68.4 (0.159)	-2	Stringent	# 29-5, WT	No. 6 oil	7-1
9.4/11.7 (32)/(40)	LEA 4.3-3.8	43.64 (18,773)	0.30	1.91	0.07	1	109 (0.254)	--	--	100 (0.234)	8	Intermediate	# 37-2, WT	No. 6 oil	7-1
16.4/25 (56)/(85)	LEA 7.6-5.4	--	0.32	0.35	0.010	1	188 (0.438)	--	--	145 (0.337)	23	--	# 7-3, WT	No. 5 oil	7-1
13.8/17.3 (47)/(59.2)	LEA 5.0-2.3	--	0.38	0.63	0.014	1	362 (0.843)	--	--	301 (0.697)	17	--	# 2-2, WT	PS 300 oil (No. 5 oil)	7-1
15.2/19.0 (52)/(65)	LEA 5.7-3.4	--	0.38	0.63	0.014	1	280 (0.651)	--	--	250 (0.581)	11	--	# 2-4, WT	PS 300 oil (No. 5 oil)	7-1

T-1583

[a] All reported tests were short-term (3 hr).

[b] NO_x emissions determined by chemiluminescence in all cases.

[c] Based on average of all tests.

[d] Moderate, intermediate or stringent levels discussed in Section 3.

[e] Excess oxygen, %, first value is high excess air (baseline) condition; second value is low excess air condition.

[f] MJ/kg (Btu/lb).

[g] FT, firetube; WT, watertube.

* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-10. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH STAGED COMBUSTION AIR (SCA)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
1.8/3.5 (6)/(12)	SCA[e] ϕ = 0.76	44.67[g] (19,219)	0.26	0.32	0.01	1	96.2 (0.224)	--	--	49.0 (0.114)	49	Stringent	# ECCC, FT[h]	No. 5 oil 2% excess O_2 Lance depth 2.5 diameters	7-2
1.8/3.5 (6)/(12)	SCA[e] ϕ = 0.65	44.67 (19,219)	0.26	0.32	0.01	2	96.2 (0.224)	51.9 (0.121)	51.9 (0.121)	51.9 (0.121)	46	Stringent	# ECCC, FT	No. 5 oil 4.4% excess O_2 Lance depth 2.5 diameters	7-2
4.0/5.1 (13.7)/(17.5)	SCA[f] ϕ_B = 1.03	43.82 (18,780)	0.23	0.60	0.034	1	120 (0.280)	--	--	84.9 (0.197)	29	Stringent	# 19-1, WT	No. 6 oil 3.1% excess O_2 Lance depth 1.5 m	7-3
4.2/5.1 (14.5)/(17.5)	SCA[f] ϕ_B >1	43.82 (18,780)	0.23	0.60	0.034	1	120 (0.280)	--	--	70 (0.162)	42	Stringent	# 19-1, WT	No. 6 oil 1.9% excess O_2 Lance depth 2.1 m	7-3
11.1/13.2 (38)/(45)	SCA[f] ϕ_B >1	42.92 (18,466)	0.31	1.88	0.05	1	168[i] (0.390)	--	--	97.4[i] (0.227)	42	Intermediate	# 38-2, WT	No. 6 oil 3.3% excess O_2	7-3

T-1588 T-1588

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] ϕ = Burner stoichiometry.
[f] ϕ_B = Equivalence ratio, defined as ratio of stoichiometric air-fuel ratio to actual air fuel at the burner.
[g] MJ/kg (Btu/lb).
[h] FT, firetube; WT, watertube.
[i] NO only.

TABLE 7-11. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH BURNERS OUT OF SERVICE (BOOS) (Reference 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
13.8/17.3 (47)/(59.2)	BOOS	--[e]	0.38	0.63	0.014	2	363 (0.845)	294 (0.684)	346 (0.807)	320 (0.744)	12	--	# 2-2, WT[f]	Two rows of 3 burners, staggered, middle top burner on air only: PS 300 (No. 5 oil)
14.9/19.0 (51)/(65.0)	BOOS	--	0.38	0.63	0.014	1	275 (0.640)	--	--	248 (0.577)	10	--	# 2-4, WT	Two rows of 3 burners, staggered, middle bottom burner on air only. PS 300 (No. 5 oil)
14.4/24.9 (49)/(85)	BOOS	--	0.32	0.35	0.010	2	192 (0.446)	139 (0.322)	153 (0.356)	146 (0.340)	24	--	# 7-3, WT	Single row of 4 burners, a middle burner on air only. (No. 5 oil)
34.9/46.9 (119)/(160)	BOOS	43.96 (18,910)	0.26	1.03	0.032	1	133 (0.309)	--	--	94.2 (0.219)	29	Intermediate	# 18-4, WT	Two rows of 2 burners one top burner on air only (No. 6 oil)
22.3/30.8 (76)/(105)	BOOS	43.96 (18,910)	0.26	1.03	0.032	7	134 (0.311)	122 (0.283)	128 (0.321)	127 (0.296)	5	Moderate	# 18-3, WT[f]	Two rows of 2 burners, one top on air only. No. 6 oil. Excess O_2 6%.
17.6/26.4 (60)/(90)[g]	BOOS	42.82 (18,420)	0.26	1.04	0.031	1	138 (0.321)	--	--	98.2 (0.228)	29	Intermediate	# 18-2, WT	One row of 3 burners, center burner on air only. No. 6 oil
8.5/20.5 (29)/(70)	BOOS	--	--	--	--	3	128 (0.299)	125 (0.291)	137 (0.244)	130 (0.303)	-2	Moderate	# 28-1, WT	One row of 3 burners, center burner on air only. No. 6 oil. Excess O_2 6%
21/44 (70)/(150)	BOOS	42.34[e] (18,213)	0.31	2.74	0.03	1	145 (0.337)	--	--	104 (0.243)	28	Intermediate	# 29-5, WT[f]	Two burners top burners on air only. No. 6 oil. Excess O_2 5.5%

T-1589

[a] All reported tests were short-term (3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] MJ/kg (Btu/lb).
[f] WT, watertube.
[g] Baseline at 71 x 10^6 Btu/hr, 7.4% excess O_2; BOOS at 60 x 10^6 Btu/hr, 0.2% excess O_2.

TABLE 7-12. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH FLUE GAS RECIRCULATION (FGR)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
1.2/3.5 (4)/(12)	FGR, 23%[e]	44.37[f] (19,091)	0.22	0.44	0.09	2	98.1 (0.288)	95.4 (0.222)	100 (0.233)	97.7 (0.227)	0	Intermediate	# ECCC, FT[g]	No. 5 oil	7-2
1.2/3.5 (4)/(12)	FGR, 40%	44.37 (19,091)	0.22	0.44	0.09	3	9.99 (0.232)	83.0 (0.193)	95.9 (0.223)	88.6 (0.206)	11	Intermediate	# ECCC, FT	No. 5 oil	7-2
1.2/3.5 (4)/(12)	FGR, 53%	44.37 (19,091)	0.22	0.44	0.09	1	94.8 (0.220)	--	--	63.4 (0.147)	33	Stringent	# ECCC, FT	No. 5 oil	7-2
1.8/3.5 (6)/(12)	FGR, 29%	44.37 (19,091)	0.22	0.44	0.09	1	108 (0.251)	--	--	82.5 (0.192)	24	Stringent	# ECCC, FT	No. 5 oil	7-2
1.8/3.5 (6)/(12)	FGR, 40%	44.37 (19,091)	0.22	0.44	0.09	1	108 (0.251)	--	--	81.9 (0.190)	24	Stringent	# ECCC, FT	No. 5 oil	7-2
3.1/3.5 (10.5)/(12)	FGR, 20%	44.37 (19,091)	0.22	0.44	0.09	2	95.9 (0.223)	66.2 (0.154)	71.8 (0.167)	69.0 (0.160)	28	Stringent	# ECCC, FT	No. 5 oil	7-2
2.9/7.3 (10)/(25)	FGR, 21%	44.60 (19,188)	0.19	0.40	0.01	3	53.9 (0.125)	43.8 (0.102)	52.4 (0.122)	47.0 (0.109	13	Stringent	# ECCC, WT	No. 5 oil	7-2
1.9/7.3 (6.5)/(25)	FGR, 17%	44.60 (19,188)	0.19	0.40	0.01	2	68.4 (0.159)	50.5 (0.117)	58.9 (0.137)	55.0 (0.128)	20	Stringent	# ECCC, WT	No. 5 oil	7-2
4.4/7.3 (15)/(25)	FGR, 9%	44.60 (19,188)	0.19	0.40	0.01	3	66.8 (0.155)	65.1 (0.151)	71.2 (0.166)	67.9 (0.158)	-2	Stringent	# ECCC, WT	No. 5 oil	7-2
4.4/7.3 (15)/(25)	FGR, 24%	44.60 (19,188)	0.19	0.40	0.01	1	66.8 (0.155)	--	--	65.1 (0.151)	3	Stringent	# ECCC, WT	No. 5 oil	7-2
4.2/5.1 (14.4)/(17.5)	FGR, 20%	45.0 (18,365)	0.14	0.37	0.009	1	95 (0.221)	--	--	81 (0.188)	15	Stringent	# 19-1, WT	Steam atomization No. 6 oil	7-2
4.2/5.1 (14.4)/(17.5)	FGR, 16%	45.0 (19,365)	0.14	0.37	0.009	1	90 (0.209)	--	--	83 (0.193)	8	Stringent	# 19-1, WT	Air atomization No. 6 oil	7-1

[a] All reported tests were short-term (3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Mass percent flue gas recirculated
[f] MJ/kg (Btu/lb).
[g] FT, firetube; WT, watertube

T-1590

TABLE 7-13. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH COMBINED FLUE GAS RECIRCULATION AND STAGED COMBUSTION AIR (FGR/SCA) (REFERENCE 7-3)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
4.3/5.1 (14.6)/(17.5)	FGR, 23.1[e] SCA, ϕ_B = 1.01[f]	43.849 (18,850)	0.22	0.60	0.026	1	120 (0.280)	--	--	90.5 (0.210)	25	Intermediate	# 19-1, WT[h]	No. 6 oil 4.2% excess O_2 Lance depth 1.2 m
4.3/5.1 (14.6)/(17.5)	FGR, 23% SCA, ϕ_B = 1.1	43.68 (18,780)	0.23	0.60	0.034	1	130 (0.303)	--	--	69* (0.16)	53	Stringent	# 19-1, WT	No. 6 oil 2.9% excess O_2 Lance depth 2.1 m
4.3/5.1 (14.6)/(17.5)	FGR, 19.6% SCA, ϕ_B = 1.21	43.68 (18,780)	0.23	0.60	0.034	1	130 (0.303)	--	--	65* (0.151)	50	Stringent	# 19-1, WT	No. 6 oil 1.5% excess O_2 Lance depth 1.2 m

T-1591

[a] All reported tests were short-term (≲3 hr).

[b] NO_x emissions determined by chemiluminescence in all cases.

[c] Based on average of all tests.

[d] Moderate, intermediate or stringent levels discussed in Section 3.

[e] Mass percent flue gas recirculation.

[f] $_B$ = Equivalence ratio, defined as ratio of stoichiometric air-fuel ratio to actual air fuel ratio at the burner.

[g] MJ/kg (Btu/lb).

[h] WT, watertube.

* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-14. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH REDUCED AIR PREHEAT (RAP) (REFERENCE 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
9.1/13.2 (31)/(45)	RAP[e] 430-350	44.69[f] (19,227)	0.49	0.19	0.08	1	183 (0.425)	--	--	153 (0.355)	16	--	38-2, WT[g]	No. 6 oil Excess O_2 3%
9.4/11.7 (32)/(40)	RAP 381.5-315.4	45.07 (19,390)	0.30	1.91	0.07	1	109 (0.254)	--	--	104 (0.241)	5	Moderate	37-2, WT	No. 6 oil Excess O_2 4%

T-1592

[a] All reported tests were short-term (<3 hr).

[b] NO_x emissions determined by chemiluminescence in all cases.

[c] Based on average of all tests.

[d] Moderate, intermediate or stringent levels discussed in Section 3.

[e] First value, temperature (K) of baseline combustion air; second value temperature (K) of RAP combustion air.

[f] MJ/kg (Btu/lb).

[g] WT, watertube boiler

TABLE 7-15. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH LOAD REDUCTION (LR) (REFERENCE 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
-/5.0 -/(17)	LR[e] 126-71	43.77[f] (18,830)	0.28	1.72	0.055	1	120 (0.279)	--	--	104 (0.241)	13	Intermediate	# 15-2-1, FT[g]	NSF (No. 5) oil Excess O_2 7%
-/3.1 -/10.5)	LR 104-62	43.61 (18,760)	0.20	1.30	0.26	1	104 (0.243)	--	--	97.6 (0.227)	6	Intermediate	# 24-TV, FT	No. 5 oil Excess O_2 2.5%
-/5.3 -/(18)	LR 98-42	42.31 (18,200)	0.10	1.46	0.007	1	99.9 (0.232)	--	--	86.4 (0.201)	14	Stringent	# 26-1, FT	No. 5 oil, air atomization Excess O_2 7.3%
-/5.3 -/(18)	LR 96-39	42.31 (18,200)	0.10	1.46	0.007	1	90.9 (0.211)	--	--	87.0 (0.202)	4	Stringent	# 26-1, FT	No 5 oil, steam atomization. Excess O_2 7%
-/3.2 -/(11)	LR 77-38	42.31 (18,200)	0.10	1.46	0.007	1	99.9 (0.232)	--	--	90.9 (0.211)	10	Intermediate	# 26-2, FT	No. 5 oil Excess O_2 7.5%
-/24.9 -/(85)	LR 69-46	--	0.32	0.35	0.010	1	185 (0.429)	--	--	141 (0.329)	24	--	# 7-3, WT	No. 5 oil Excess O_2 7.7% Preheated air
-/26.4 -/(90)	LR 80-46	42.82 (18,420)	0.26	1.04	0.031	1	160 (0.372)	--	--	108 (0.250)	33	Intermediate	# 18-2, WT	No. 6 oil. Excess O_2 8.5%. Preheated air.
-/30.8 -/(105)	LR 76-44	44.00 (18,930)	0.29	1.03	0.043	1	176 (0.410)	--	--	123 (0.287)	30	Moderate	# 18-3, WT	No. 6 oil. Excess O_2 7.6%. Preheated air.
-/46.9 -/(160)	LR 75-45	44.00 (18,930)	0.29	1.03	0.043	1	144 (0.335)	--	--	180 (0.419)	-25	--	# 18-4, WT	No. 6 oil. excess O_2 8%. Preheated air.

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Percent rated load, first value is high load, second value is low load.
[f] MJ/kg (Btu/lb).
[g] FT, firetube; WT, watertube.

Continued

T-1593

TABLE 7-15. Concluded

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
-/44 -/(150)	LR[e] 79-47	42.33[f] (18,213)	0.31	2.74	0.03	1	165 (0.384)	--	--	145 (0.337)	12	--	# 29-5, WT[g]	No. 6 oil. excess O_2 5%. Preheated air.
-/17.3 -/(59)	LR 100-81	--	--	0.63	0.014	1	241 (0.560)	--	--	225 (0.523)	7	--	# 2-2, WT	PS 300 (No. 5) oil. Excess O_2 3%
-/19.0 -/(65)	LR 77-68	--	--	0.63	0.014	1	264 (0.614)	--	--	270 (0.628)	-2	--	# 2-4, WT	PS 300 (No. 5) oil. Excess O_2 3%
-/36.6 -/(125)	LR 80-30	--	0.52	1.15	0.026	1	215 (0.500)	--	--	197 (0.458)	8	--	#2-6, WT	PS300 (No. 5) oil. Excess O_2 7%
-/5.1 -/(17.5)	LR 83-55	42.49 (18,280)	0.44	2.80	0.044	1	219 (0.510)	--	--	210 (0.489)	4	--	#19-1, WT	No. 6 oil. Excess O_2 6%
-/23.4 -/(80)	LR 75-41	43.14 (18,560)	0.37	1.53	0.032	1	184 (0.428)	--	--	155 (0.361)	16	--	#20-4, WT	No. 6 oil. Excess O_2 6%
-/29.3 -/(100)	LR 85-55	42.62 (18,333)	0.77	1.29	0.10	1	257 (0.598)	--	--	246 (0.573)	4	--	#27-1, WT	PS 300 (No. 5) oil Excess O_2 9%
-/3.5 -/(12)	LR 92-46	44.34 (19,075)	0.04	0.67	0.04	1	120 (0.280)	--	--	110 (0.255)	8	Moderate	#ECCC, FT	No. 5 oil. Excess O_2 4% (Reference 7-2).
-/7.3 -/(25)	LR 74-26	44.40 (19,099)	0.15	0.75	0.02	1	71.2 (0.165)	--	--	68.3 (0.159)	4	Stringent	#ECCC, WT	No. 5 oil Excess O_2 4.5% (Reference 7-2).

T-1593

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Percent rated load, first value is high load, second value is low load.
[f] MJ/kg (Btu/lb)
[g] FT, firetube; WT, watertube

boiler. The fuel characteristics columns exemplify the differences in fuels that, due to viscosity, are both labeled as No. 6 oils.

Data on NO_x emission controls as applied to boilers burning distillate oil are contained in Tables 7-16 through 7-20. The tests were selected because they best fitted the criteria for selection listed in Section 7.1. All of the data resulted from two EPA sponsored field investigations and one subsequent study of a boiler with major modifications (References 7-1, 7-3 through 7-5).

All distillate oils used were classified as No. 2. All had comparable higher heating values and sulfur, nitrogen, and ash contents.

7.4 EMISSION SOURCE TEST DATA FOR GAS-FIRED BOILERS

Emission source test data for NO_x controls on industrial boilers burning natural gas are presented in Tables 7-21 through 7-27. A large number of tests were conducted using this fuel under various EPA sponsored programs (References 7-1 through 7-5). The criteria whereby these tests were chosen as representative were presented in Section 7-1.

7.5 DEVELOPING EMISSION SOURCE TEST DATA

EPA is currently sponsoring several field test programs demonstrating combustion modification NO_x controls for industrial boilers. These programs include identification of optimal combustion conditions for 11 stoker coal-fired boilers, sponsored jointly with the Department of Energy (References 7-8 and 7-10), and field demonstrations of the TRW low NO_x burner for both oil- and gas-firing (References 7-11 and 7-12). The imminent results from these studies should help fill some of the data gaps identified in this study. In addition, several other field tests of these and other combustion controls are being planned, including 30-day continuous monitoring programs (Reference 7-12). The results of these and other test programs should be monitored and incorporated in future updates of the assessment of combustion modification NO_x controls.

TABLE 7-16. NO_x EMISSION TEST DATA FROM DISTILLATE (NO. 2) OIL-FIRED INDUSTRIAL BOILERS WITH LOW EXCESS AIR (LEA) (REFERENCE 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
1.6/2.9 (5.5)/(10.0)	LEA[e] 5.6-3.6	--[f]	--	0.23	--	1	96.5 (0.224)	--	--	85.8 (0.200)	11	Moderate	#3-2, FT[g]	No air preheat.
2.7/5.9 (9.3)/(20.0)	LEA 5.2-2.7	--	--	0.30	--	1	107 (0.248)	--	--	81.3 (0.189)	24	Moderate	#4-4, FT	No air preheat.
3.3/3.2 (11.3)/(11)	Baseline 4.7	45.12 (19,410)	0.02	0.48	0.001	1	70.5 (0.164)	--	--	--	--	Moderate	26-2, FT	Air atomization
4.7/5.3 (15.9)/(18)	Baseline 8.0	45.12 (19,410)	0.02	0.48	0.001	1	63.8 (0.149)	--	--	--	--	Intermediate	26-1, FT	Air atomization
4.6/5.3 (15.7)/(18)	Baseline 8.0	45.12 (19,410)	0.02	0.48	0.001	1	65.0 (0.151)	--	--	--	--	Intermediate	26-1, FT	Air atomization
2.0/2.1 (6.7)/(7)	Baseline 6.8	45.12 (19,410)	0.015	0.38	0.002	1	70.0 (0.163)	--	--	--	--	Moderate	23-1, FT	Air atomization
3.2/3.8 (11)/(13)	Baseline 3.1	45.12 (19,410)	0.015	0.19	0.001	1	46.4 (0.108)	--	--	--	--	Intermediate	24-TV, FT	Air atomization
5.4/8.5 (18.5)/(29.0)	LEA 5.9-4.5	45.19 (19,440)	0.045	0.40	0.003	1	54.4 (0.127)	--	--	51.6 (0.120)	5	Intermediate	#1-1, WT	No air preheat.
7.0/8.5 (24.0)/(29.0)	LEA 3.8-2.7	45.19 (19,440)	0.045	0.40	0.003	1	48.2 (0.112)	--	--	47.7* (0.111)	1	Intermediate	#1-1, WT	Higher load. No air preheat.
4.2/8.5 (14.5)/(29.0)	LEA 8.2-5.1	45.19 (19,440)	0.045	0.40	0.003	1	59.5 (0.138)	--	--	51.6 (0.120)	11	Intermediate	#1-2, WT	No air preheat.
6.9/8.8 (23.5)/(30)	LEA 5.9-2.8	--	0.031	0.22	0.001	1	69.0 (0.160)	--	--	58.3 (0.136)	16	Intermediate	#1-3, WT	
4.1/5.1 (14)/(17.5)	LEA 3.6-2.6	45.26 (19,470)	0.006	0.06	0.001	1	37.0 (0.086)	--	--	35.9* (0.083)	3	Stringent	# 19-1, WT[g]	Steam atomization. No air preheat.
4.1/5.1 (14)/(17.5)	LEA 3.0-1.6	45.26 (19,470)	0.006	0.06	0.001	1	51.0 (0.119)	--	--	50.5 (0.117)	1	Intermediate	# 19-1, WT	Air atomization. No air preheat.
3.4/5.1 (11.6)/(17.5)	LEA 4.3-3.7	45.26 (19,470)	0.006	0.06	0.001	1	46.0 (0.107)	--	--	46.0 (0.107)	0	Intermediate	# 19-1, WT	Mechanized atomization. No air preheat.
25.8/32.2 (88)/(110)	LEA 5.7-3.8	44.95 (19,340)	0.01	0.18	0.004	1	102 (0.236)	--	--	93.7 (0.218)	8	--	# 17-T-8, WT	

[a] All reported tests were short-term (3 hr).
[b] NO_x emissions determined by chemiluminescence ir all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Excess oxygen, %; first value is high excess air (baseline) condition; second value is low excess air condition.
[f] MJ/kg (Btu/lb).
[g] FT, firetube; WT, watertube.
*May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-17. NO_x EMISSION TEST DATA FROM DISTILLATE (NO. 2) OIL-FIRED INDUSTRIAL BOILERS WITH FLUE GAS RECIRCULATION (FGR) (REFERENCE 7-3)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
4.3/5.1 (14.6)/(17.5)	FGR, 28%[e]	45.61[f] (19,610)	0.008	0.14	0.001	2	67.4 (0.157)	17.4 (0.040)	18.5 (0.043)	18.0 (0.042)	73	Stringent	#19-1, WT[g]	Excess O_2 0.8% No air preheat.
4.3/5.1 (14.6)/(17.5)	FGR, 15%	45.78 (19,680)	<0.001	0.10	<0.001	1	~59 ~(0.14)	--	--	25 (0.058)	58	Stringent	#19-1, WT	Excess O_2 1% No air preheat.

T-1595

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Mass percent flue gas recirculated.
[f] MJ/kg (Btu/lb).
[g] WT, watertube.

TABLE 7-18. NO_x EMISSION TEST DATA FROM DISTILLATE (NO. 2) OIL-FIRED INDUSTRIAL BOILERS WITH STAGED COMBUSTION AIR (SCA) (REFERENCE 7-3)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
4.3/5.1 (14.5)/(17.5)	SCA, ϕ_B = 1.04[e]	45.61[f] (19,610)	0.008	0.14	0.001	2	66.0 (0.153)	54.0 (0.126)	55.1 (0.128)	54.6* (0.127)	17	Intermediate	#19-1, WT[g]	Excess O_2 3.1% Lance depth, 1.8 m.
4.3/5.1 (14.5)/(17.5)	SCA, ϕ_B = 1.10	45.78 (19,680)	<0.001	0.10	<0.001	1	66.0 (0.153)	--	--	29.0 (0.068)	44	Stringent	#19-1, WT	Excess O_2 2.6% Lance depth 2.1 m.
4.3/5.1 (14.5)/(17.5)	SCA, ϕ_B = 1.10	45.78 (19,680)	<0.001	0.10	<0.001	1	56 (0.13)	--	--	39* (0.091)	30	Stringent	#19-1, WT	Excess O_2 3%. Lance depth, 2.1 m. No air preheat.

T-1596

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] ϕ_B = Equivalence ratio, defined as ratio of stoichiometric air-fuel ratio to actual air-fuel ratio at burner.
[f] MJ/kg (Btu/lb).
[g] WT, watertube.
* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-19. NO_x TEST DATA FROM DISTILLATE (NO. 2) OIL-FIRED INDUSTRIAL BOILERS WITH COMBINED FLUE GAS RECIRCULATION AND STAGED COMBUSTION AIR (FGR/SCA) (REFERENCE 7-3)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
4.3/5.1 (14.6)/(17.5)	FGR, 26.3%[e] SCA, ϕ_B = 1.10[f]	--	--	--	--	1	67.4 (0.157)	--	--	18.0 (0.042)	73	Stringent	#19-1, WT[h]	Excess O_2 3.9%. Lance depth, 1.2 m. No air preheat.
4.3/5.1 (14.6)/(17.5)	FGR, 26% SCA ϕ_B = 1.1	45.619 (19,610)	0.008	0.14	0.001	1	67.4 (0.157)	-	-	16 (0.036)	77	Stringent	#19-1, WT	Excess O_2 2.5%. Lance depth, 2.1 m. No air preheat.

T-1597

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Mass percent flue gas recirculated.
[f] Equivalence ratio, defined as ratio of stoichiometric air-fuel ratio to actual air-fired ratio at the burner.
[g] MJ/kg (Btu/lb).
[h] WT, watertube.

TABLE 7-20. NO$_x$ EMISSION TEST DATA FROM DISTILLATE (NO. 2) OIL-FIRED INDUSTRIAL BOILERS WITH LOAD REDUCTION (LR) (REFERENCE 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO$_x$ Emissions[b] ng NO$_2$/J (lb NO$_2$/10^6 Btu)	Controlled NO$_x$ Emissions[b] ng NO$_2$/J (lb NO$_2$/10^6 Btu)			Percent NO$_x$ Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
-/2.9 -/(10.0)	70-30[e]	--[f]	--	0.23	--	1	95.9 (0.223)	--	--	86.4 (0.201)	10	Moderate	#3-2, FT[g]	Excess O$_2$ 7% No air preheat.
-/5.9 -/(20)	92.5-46.5	--	--	0.30	--	1	106 (0.247)	--	--	108 (0.252)	-2	--	#4-4, FT	Excess O$_2$ 6.4% No air preheat.
-/8.5 -/(29)	81-64	45.19 (19,440)	0.045	0.40	0.003	1	44.3 (0.103)	--	--	51.6 (0.120)	-17	Intermediate	#1-1, WT	Excess O$_2$ 4%. No air preheat.
-/8.5 -/(29)	66-50	45.19 (19,440)	0.045	0.40	0.003	1	48.8 (0.113)	--	--	51.6 (0.120)	-6	Intermediate	#1-2, WT	Excess O$_2$ 5%. No air preheat.
-/58.6 -/(200)	45-18	45.07 (19,390)	0.013	0.31	0.001	1	58.3 (0.136)	--	--	60.6 (0.141)	-4	Intermediate	#36-6, WT	Excess O$_2$ increased from 3.3% to 9.0%. No air preheat.
-/46.3 -/(158)	89-73	--	0.018	0.23	0.005	1	151 (0.351)	--	--	104 (0.241)	31	-	#6-3, WT	Excess O$_2$ 5%.
-/32.2 -/(110)	80-30	44.96 (19,340)	0.01	0.18	0.004	1	114 (0.265)	--	--	88.6 (0.206)	22	Moderate	#17-T8, WT	Excess O$_2$ 8%.

T-1598

[a] All reported tests were short-term (<3 hr).

[b] NO$_x$ emissions determined by chemiluminescence in all cases.

[c] Based on average of all tests.

[d] Moderate, intermediate or stringent levels discussed in Section 3.

[e] Percent rated load, first value is high load (baseline), second value is low load.

[f] MJ/kg (Btu/lb).

[g] FT, firetube; WT, watertube

TABLE 7-21. NO_x EMISSION TEST DATA FROM GAS-FIRED INDUSTRIAL BOILERS WITH LOW EXCESS AIR (LEA)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
1.46/2.9 (5.0)/(10.0)	LEA[e] 8.0-3.6	36.65[f] (1100)	--	--	--	1	51.0 (0.119)	--	--	33.7 (0.078)	34	Stringent	# 3-2, FT[g]	No air preheat	7-1
4.1/5.9 (14.0)/(20)	LEA 6.8-0.7	36.65 (1100)	--	--	--	1	55.1 (0.128)	--	--	40.3 (0.094)	27	Stringent	# 4-4, FT	No air preheat	7-1
2.6/5.9 (9.0)/(20)	LEA 6.8-1.2	36.65 (1100)	--	--	--	1	52.5 (0.122)	--	--	43.3 (0.101)	18	Stringent	# 4-4, FT	Low load No air preheat	7-1
2.3/2.9 (8.0)/(10.0)	LEA 5.1-1.9	36.65 (1100)	--	--	--	1	28.6 (0.066)	--	--	20.4* (0.047)	29	Stringent	# 5-248-3, FT	No air preheat	7-1
1.9/2.3 (6.4)/(8.0)	LEA 11.0-3.2	36.65 (1100)	--	--	--	1	31.6 (0.074)	--	--	24.0 (0.056)	24	Stringent	# 5-248-1, FT	No air preheat	7-1
3.6/3.1 (12.4)/(10.5)	LEA 4.1-3.1	31.96 (966)	--	--	--	1	31.6 (0.074)	--	--	32.6 (0.076)	-3	Stringent	# 24-TV, FT	No air preheat	7-1
5.0/5.3 (17.2)/(18)	LEA 7.2-2.7	31.89 (964)	--	--	--	1	29.6 (0.069)	--	--	38.8 (0.090)	-31	Stringent	# 26-1, FT	No air preheat	7-1
3.05/3.2 (10.4)/(11)	LEA 3.6-2.9	31.89 (964)	--	--	--	1	47.9 (0.111)	--	--	48.4* (0.113)	-1	Intermediate	# 26-2, FT	No air preheat	7-1
1.1/3.5 (3.8)/(12)	LEA 11.5-8.0	--	--	--	--	1	53.6 (0.124)	--	--	44.9 (0.104)	16	Intermediate	# ECCC, FT	No air preheat	7-2
2.0/3.5 (6.8)/(12)	LEA 9.0-6.5	--	--	--	--	1	52.0 (0.121)	--	--	45.9 (0.107)	12	Intermediate	# ECCC, FT	No air preheat	7-2

T-1613

Continued

[a] All reported tests were short-term (<3 hr).

[b] NO_x emissions determined by chemiluminescence in all cases.

[c] Based on average of all tests.

[d] Moderate, intermediate or stringent levels discussed in Section 3.

[e] Excess oxygen, %, first value is high excess air (baseline) condition, second value is low excess air condition.

[f] MJ/m^3, (Btu/ft^3)

[g] FT, firetube; WT, watertube.

* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-21. Continued

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
6.9/8.5 (23.5)/(29)	LEA 4.5-1.9[e]	36.65[f] (1108)	--	--	--	1	36.7 (0.085)	--	--	33.1 (0.077)	10	Stringent	# 1-1, WT[g]	No air preheat	7-1
5.0/8.5 (17.0)/(29)	LEA 6.4-2.2	36.65 (1108)	--	--	--	1	37.7 (0.088)	--	--	39.8 (0.093)	-6	Stringent	# 1-2, WT	No air preheat	7-1
3.2/7.3 (11.0)/(25)	LEA 8.9-5.0	36.65 (1108)	--	--	--	1	41.8 (0.097)	--	--	7.14 (0.0166)	83	Stringent	# 5-716-3, WT	No air preheat	7-1
25/32 (87)/(110)	LEA 8.1-2.0	37.35 (1129)	--	--	--	1	47.9 (0.111)	--	--	82.1 (0.191)	-71	Moderate	# 10-5, WT	No air preheat	7-1
4.1/5.1 (14)/(17.5)	LEA 3.2-2.0	33.84 (1023)	--	--	--	1	30.1 (0.070)	--	--	28.0 (0.065)	7	Stringent	# 19-1, WT	No air preheat	7-1
47/59 (160)/(200)	LEA 3.7-1.3	27.50 (831)	--	--	--	1	97.9 (0.228)	--	--	97.4 (0.227)	1	--	# 39-810B, WT	No air preheat	7-1
2.9-4.1/7.3 (10-14)/(25)	LEA 6.3-2.4	--	--	--	--	2	34.7 (0.081)	30.6 (0.071)	31.1 (0.072)	30.9 (0.072)	11	Stringent	# ECCC, WT[g]	No air preheat	7-2
7.0/8.8 (24)/(30)	LEA 5.7-2.7	36.65 (1108)	--	--	--	1	49.0 (0.113)	--	--	39.3 (0.091)	20	Stringent	# 1-3, WT		7-1
40/47 (135)/(160)	LEA 3.8-2.6	37.35 (1129)	--	--	--	1	191 (0.402)	--	--	173 (0.402)	9	--	# 9-BC-6, WT		7-1
23/38 (77)/(130)	LEA 6.6-6.1	34.73 (1050)	--	--	--	1	105 (0.253)	--	--	100 (0.234)	4	--	# 32-4, WT		7-1
44/73 (150)/(250)	LEA 6.5-3.7	34.63 (1047)	--	--	--	1	96.4 (0.224)	--	--	87.2 (0.203)	10	Moderate	# 34-2, WT		7-1
12/13 (40)/(45)	LEA 1.9-1.4	33.81 (1011)	--	--	--	1	112 (0.261)	--	--	92.8* (0.216)	17	--	# 38-2, WT		7-1

T-16.3

Continued

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Excess oxygen, %, first value is high excess air (baseline) condition, second value is low excess air condition.
[f] MJ/m^3 (Btu/ft^3)
[g] FT, firetube; WT, watertube
* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-21. Concluded

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
16/19.0 (53)/(65.0)	LEA[e] 4.5-3.0	36.65[f] (1100)	--	--	--	1	43.9 (0.102)	--	--	43.9* (0.102)	0	Stringent	# 2-4, WT[g]	No air preheat	7-1
14.5/18 (49.4)/(60)	LEA 5.2-2.5	37.35 (1129)	--	--	--	1	53.0 (0.123)	--	--	56.1 (0.130)	-6	Intermediate	# 10-4, WT	No air preheat	7-1
35/46.3 (120)/(158)	LEA 13.1-10.8	33.65 (1108)	--	--	--	1	168 (0.391)	--	--	127 (0.295)	24	--	# 6-3, WT		7-1
13.5/18 (46)/(60)	LEA 2.6-1.4	37.35 (1129)	--	--	--	1	123 (0.286)	--	--	80.1* (0.186)	35	Moderate	# 9-BC-1, WT		7-1
53.9/65.9 (184)/(225)	LEA 6.1-4.4	51.21 (1548)	--	--	--	1	102 (0.237)	--	--	70.9* (0.165)	30	Moderate	# 12-24, WT		7-1
8.8/21 (30)/(70)	LEA 5.7-3.7	37.3 (1000)	--	--	--	1	100 (0.234)	--	--	84.7 (0.197)	22	Moderate	# 28-1, WT		7-1
35/44 (120)/(150)	LEA 5.3-3.2	37.3 (1000)	--	--	--	1	76 (0.177)	--	--	81.6 (0.190)	-4	Moderate	# 29-5, WT		7-1
24/35 (83)/(120)	LEA 4.4-2.2	39.1 (1051)	--	--	--	1	117 (0.273)	--	--	111 (0.258)	5	--	# 32-1, WT		7-1

T-1613

[a] All reported tests were short-term (<3 hr).

[b] NO_x emissions determined by chemiluminescence in all cases.

[c] Based on average of all tests.

[d] Moderate, intermediate or stringent levels discussed in Section 3.

[e] Excess oxygen, %, first value is high excess air (baseline) condition, second value is low excess air condition.

[f] MJ/m^3, (Btu/ft^3).

[g] FT, firetube, WT, watertube.

* May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-22. NO_x EMISSION TEST DATA FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS WITH STAGED COMBUSTION AIR (SCA) (REFERENCE 7-3)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
2.5/3.5 (8.5)/(12)	SCA[e] ϕ = 57%	--	--	--	--	1	36.3 (0.084)	--	--	34.5 (0.080)	5	Stringent	# ECCC, FT[h]	Overall excess O_2: 2.9% (SCA), 1.9% (baseline) (Ref. 7-2) No air preheat
1.2/3.5 (4)/(12)	SCA[e] ϕ = 129%	--	--	--	--	1	28.0 (0.065)	--	--	23.6* (0.055)	16	Stringent	# ECCC, FT	Overall excess O_2: 7.6% (SCA), 8.0% (baseline) (Ref. 7-2) No air preheat
4.3/5.1 (14.5)/(17.5)	SCA[f] ϕ_B = 0.97%	38.69 (1035)	--	--	--	1	45.9 (0.107)	--	--	25.0 (0.058)	46	Stringent	# 19-1, WT	Lance at 2.1 m Overall excess O_2 2.8% No air preheat
11.3/13.2 (38.7)/(45)	SCA[f] ϕ_B = NA	37.7 (1011)	--	--	--	1	82.1 (0.191)	--	--	56.6 (0.132)	31	Intermediate	# 30-2, WT	Overall excess O_2 2.25%

T-1614

[a] All reported tests were short-term (<3 hr).

[b] NO_x emissions determined by chemiluminescence in all cases.

[c] Based on average of all tests.

[d] Moderate, intermediate or stringent levels discussed in Section 3.

[e] ϕ = Burner stoichiometry.

[f] ϕ_B = Equivalence ratio, defined as ratio of stoichiometric air-fuel ratio to actual air-fuel ratio at the burner.

[g] MJ/m^3 (Btu/ft^3).

[h] FT, firetube, WT, watertube.

*May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-23. NO_x EMISSION TEST DATA FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS WITH FLUE GAS RECIRCULATION (FGR)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
1.75/3.5 (6)/(12)	FGR 30%[e]	--	--	--	--	3	41 (0.095)	10 (0.023)	14 (0.032)	13 (0.030)	68	Stringent	# ECCC, FT[f]	Excess O_2 4% No air preheat	7-2
1.75/3.5 (6)/(12)	FGR 50%	--	--	--	--	3	41 (0.095)	8.2 (0.019)	9.2 (0.021)	8.9 (0.021)	79	Stringent	# ECCC, FT	Excess O_2 4% No air preheat	7-2
1.75/3.5 (6)/(12)	FGR 30%	--	--	--	--	1	33 (0.077)	--	--	9.2* (0.021)	72	Stringent	# ECCC, FT	Excess O_2 1.2% No air preheat	7-2
1.75/13.5 (6)/(12)	FGR 50%	--	--	--	--	3	33 (0.077)	3.1 (0.0071)	6.6 (0.015)	4.4 (0.010)	86	Stringent	# ECCC, FT	Excess O_2 3.5% No air preheat	7-2
2.3/3.5 (8)/(12)	FGR 55%	--	--	--	--	3	36 (0.084)	5.2 (0.012)	7.0 (0.016)	6.0* (0.014)	84	Stringent	# ECCC, FT	Comparatively high load. Excess O_2 2%. No air preheat	7-2
2.0/7.3 (7)/(25)	FGR, 12%	--	--	--	--	3	27 (0.062)	12 (0.028)	16 (0.036)	14 (0.031)	48	Stringent	# ECCC, WT	Excess O_2 1-3% No air preheat	7-2
2.0/7.3 (7)/(25)	FGR, 25%	--	--	--	--	3	27 (0.062)	6.6 (0.015)	10 (0.023)	8.2 (0.019)	70	Stringent	# ECCC, WT	Excess O_2 1-3% No air preheat	7-2
2.8/7.3 (9.5)/(25)	FGR, 22%	--	--	--	--	2	22 (0.050)	7.0 (0.016)	9.2 (0.021)	8.1 (0.019)	63	Stringent	# ECCC, WT	Excess O_2 1.2-2.6% No air preheat	7-2
4.2/5.1 (14.5)/(17.5)	FGR, 0%	34.249 (1035)	--	--	--	2	52 (0.121)	21 (0.049)	29 (0.067)	25 (0.058)	52	Stringent	# 19-1, WT	Excess O_2 1.5-3.1% No air preheat	7-3
4.2/5.1 (14.5)/(17.5)	FGR, 20%	34.24 (1035)	--	--	--	2	45.9 (0.107)	11.2 (0.026)	12.2 (0.028)	11.7 (0.027)	75	Stringent	# 19-1, WT	Excess O_2 2.5-3.2% No air preheat	7-3

T-1615

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Mass percent flue gas recirculated.
[f] FT, firetube, WT, watertube.
[g] MJ/m^3 (Btu/ft^3)
*May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-24. NO_x TEST DATA FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS WITH COMBINED FLUE GAS RECIRCULATION AND STAGED COMBUSTION (FGR/SCA) (REFERENCE 7-3)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
4.0/5.1 (13.7)/(17.5)	FGR, 17.8%[e] SCA, ϕ_B = 0.86[f]	34.249 (1035)	--	--	--	1	45.9 (0.107)	--	--	11.2 (0.026)	76	Stringent	# 19-1, WT[h]	Overall excess O_2 3.3% No air preheat

T-1616

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Mass percent flue gas recirculated.
[f] ϕ_B = Equivalence ratio, defined as ratio of stoichiometric air-fuel ratio to actual air-fuel ratio at the burner.
[g] MJ/m^3 (Btu/ft^3).
[h] WT, watertube.

TABLE 7-25. NO_x EMISSION TEST DATA FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS WITH LOAD REDUCTION (LR)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
--/2.9 --/(10)	LR 100-50[e]	36.65[f] (1108)	--	--	--	1	46.4 (0.108)	--	--	51.0 (0.119)	-10	Intermediate	# 3-2, FT[g]	No air preheat	7-1
--/5.8 --/(20)	LR 92.5-45	36.65 (1108)	--	--	--	1	52.5 (0.122)	--	--	52.5 (0.122)	0	Intermediate	# 4-4, FT	No air preheat	7-1
--/2.9 --/(10)	LR 100-50	36.65 (1108)	--	--	--	1	28.6 (0.067)	--	--	30.1 (0.070)	-5	Stringent	# 5-248-3, FT	No air preheat	7-1
--/2.3 --/(80)	LR 100-40	36.65 (1108)	--	--	--	1	39.2 (0.091)	--	--	28.0 (0.065)	29	Stringent	# 5-248-1, FT	No air preheat	7-1
--/3.8 --/(13.0)	LR 95/32	31.96 (966)	--	--	--	1	31.6 (0.073)	--	--	34.7 (0.081)	-10	Stringent	# 24-TY, FT	No air preheat	7-1
--/5.8 --/(20.0)	LR 62.5-21	31.99 (967)	--	--	--	1	43.9 (0.102)	--	--	37.2 (0.087)	15	Stringent	# 25-1, FT	No air preheat	7-1
--/3.2 --/(11)	LR 47-25	31.89 (964)	--	--	--	1	43.9 (0.102)	--	--	43.4 (0.101)	1	Stringent	# 28-2, FT	No air preheat	7-1
--/5.2 --/(18)	LR 95.6-42.8	31.89 (964)	--	--	--	1	29.6 (0.069)	--	--	27.5 (0.064)	7	Stringent	# 26-1, FT	No air preheat	7-1
--/8.4 --/(29)	LR 83-64	36.65 (1108)	--	--	--	1	41.8 (0.097)	--	--	42.8 (0.100)	-2	Stringent	# 1-1, WT	Excess O_2 3% No air preheat	7-1
--/8.4 --/(29)	LR 62-26	36.65 (1108)	--	--	--	1	39.3 (0.091)	--	--	52.0 (0.121)	-32	Intermediate	# 1-1, WT	Excess O_2 8% No air preheat	7-1
--/8.4 --/(29)	LR 85-59	36.65 (1108)	--	--	--	1	39.3 (0.091)	--	--	39.8 (0.093)	-1	Stringent	# 1-2, WT	No air preheat	7-1
--/7.3 --/(25)	LR 80-44	36.65 (1108)	--	--	--	1	38.8 (0.090)	--	--	7.1 (0.017)	82	Stringent	# 5-716-3, WT	No air preheat	7-1

T-1617

Continued

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Percent load; first value is high load (baseline), second value is low load.
[f] MJ/m^3 (Btu/ft^3).
[g] FT, firetube; WT, watertube.

TABLE 7-25. Concluded

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
--/32.2 --/(110)	LR 98-27[e]	42.1[f] (1129)	--	--	--	1	63.2 (0.147)	--	--	54.6 (0.127)	14	Intermediate	# 10-5, WT[g]	Excess O_2 7% No air preheat	7-1
--/5.1 --/(17.5)	LR 91-70	38.1 (1023)	--	--	--	1	28.6 (0.066)	--	--	30.6 (0.071)	-7	Stringent	# 19-1, WT	Excess O_2 3% No air preheat	7-1
--/29.3 --/(100)	LR 75-20	36.4 (976)	--	--	--	1	57.6 (0.134)	--	--	51.5 (0.120)	11	Intermediate	# 27-1, WT	Excess O_2 6.8% No air preheat	7-1
--/17.6 --/(60)	LR 101-82	42.1 (1129)	--	--	--	1	58.7 (0.136)	--	--	55.1 (0.128)	6	Intermediate	# 10-4, WT	Excess O_2 3.8% No air preheat	7-1
--/7.3 --/(25)	LR 78-41	--	--	--	--	1	33.2 (0.077)	--	--	35.4 (0.082)	-7	Stringent	# ECCC, WT	No air preheat	7-2
--/3.5 --/(12)	LR 73-31	--	--	--	--	1	45.9 (0.107)	--	--	45.0 (0.105)	2	Stringent	# ECCC, FT	No air preheat	7-2
--/46.3 --/(158)	LR 95-39	36.85 (1108)	--	--	--	1	178 (0.415)	--	--	53.0 (0.123)	70	Intermediate	# 6-3, WT	Excess O_2 12.5%	7-1
--/46.9 --/(160)	LR 94-79	42.1 (1129)	--	--	--	1	206 (0.479)	--	--	181 (0.421)	12	--	# 9-BC-6, WT	Excess O_2 4%	7-1
--/18 --/(60)	LR 98-57	42.1 (1129)	--	--	--	1	125 (0.290)	--	--	70.4* (0.164)	44	Moderate	# 9-BC-1, WT	Excess O_2 2%	7-1
--/65.9 --/(225)	LR 100-58	37.8 (1016)	--	--	--	1	104 (0.241)	--	--	89.8 (0.209)	14	Moderate	# 12-24, WT	Excess O_2 5.5%	7-1

T-1617

[a] All reported tests were short-term (<3 hr).

[b] NO_x emissions determined by chemiluminescence in all cases.

[c] Based on average of all tests.

[d] Moderate, intermediate or stringent levels discussed in Section 3.

[e] Percent load; first value is high load (baseline), second value is low load.

[f] MJ/m^3 (Btu/ft^3).

[g] FT, firetube; WT, watertube.

*May involve unacceptable operating conditions leading to high CO and/or smoke emissions.

TABLE 7-26. NO_x EMISSION TEST DATA FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS WITH REDUCED AIR PREHEAT (RAP) (REFERENCE 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
58.6/73.2 (200)/(250)	RAP[e] 383-303	39.0[f] (1047)	--	--	--	1	94.9 (0.221)	--	--	70.9 (0.165)	25	Moderate	# 34-2, WT[g]	Excess O_2 2.7%
44/73.2 (150)/(250)	RAP 391-308	39.0 (1047)	--	--	--	1	108 (0.250)	--	--	58.7 (0.136)	45	Intermediate	# 34-2, WT	Excess O_2 4.7%
11/13 (39)/(45)	RAP 550-480	37.7 (1011)	--	--	--	1	112 (0.261)	--	--	63.2 (0.147)	44	Intermediate	# 38-2, WT	Excess O_2 1.7%

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Combustion air temperature (K), first value is baseline, second is reduced air preheat temperature.
[f] MJ/m^3 (Btu/ft^3).
[g] WT, watertube.

T-1618

TABLE 7-27. NO_x EMISSION TEST DATA FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS WITH BURNERS OUT OF SERVICE (BOOS) (REFERENCE 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
13.5/17.6 (46)/(60)	BOOS	42.1[e] (1129)	--	--	--	3	123 (0.287)	96.9 (0.225)	107.1 (0.249)	102.5 (0.238)	17	--	# 9-BC-1, WT[f]	Two rows of two[g] burners, one upper BOOS burner on air only. Excess O_2 3%
8.5/20.5 (29)/(70)	BOOS	37.3 (1000)	--	--	--	3	108 (0.251)	49 (0.113)	70 (0.619)	60.3 (0.140)	44	Intermediate	# 28-1, WT	One row of three burners. Center burner on air only. Excess O_2 5.5%.
17.9/35.2 (61)/(120)	BOOS	39.1 (1050)	--	--	--	2	106 (0.246)	74 (0.172)	80 (0.186)	77 (0.179)	27	Moderate	# 32-1, WT	Two rows of two burners, both upper burners on air only. Excess O_2 4.4%

T-1619

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] MJ/m^3 (Btu/ft^3).
[f] WT, watertube.
[g] BOOS load, 41 x 10^6 Btu.

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7-9 Lips, H. I., and E. B. Higginbotham, "Field Testing of an Industrial Stoker Coal-Fired Boiler -- Effects of Combustion Modification NO_x Control on Emissions -- Site B," Acurex Report TR-79-18/EE, EPA Contract No. 68-02-2160, Acurex Corporation, Mountain View, CA, August 1978.

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7-11 Matthews, B. J., TRW, Inc., Redondo Beach, California, Letter to W. Peters, EPA IERL-RTP, NC, March 23, 1979.

7-12 Hall, R. E., IERL-RTP, NC, Telecommunication with K. J. Lim, Acurex Corporation, May 18, 1979.

APPENDIX A

COST DETAILS

Following are listed tables of estimated capital costs and annualized costs for combustion modification NO_x control techniques. Tables are presented for each combination of typical boiler type/candidate control system. All assumptions (capital recovery factor, load factors, engineering estimate factors, etc.) are all discussed in Sections 4 and 5. The format followed is that requested by EPA:EAB. These tables supplement the summary cost tables presented in Section 4.

TABLE A-1. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 59 MW PULVERIZED COAL-FIRED BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$16,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 5,000		
Total Direct Costs (equipment + installation)		$ 21,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 27,000	
Land			
Working capital (25% of total direct operating costs)[b]		0	
GRAND TOTAL (turnkey + land + working capital)			$ 27,000

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[a] Costs are engineering estimates based on References 4-1 and 4-10 through 4-13.
[b] From Annual Cost Table (see following table).

TABLE A-2. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 59 MW PULVERIZED COAL-FIRED BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,250		
Replacement parts			
Electricity	Negligible		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$(6,178)		
Waste disposal	0		
Chemicals	0		
Total direct cost		$(4,928)	
Overhead			
Pa[illegible] (30% of direct labor)	--		
[illegible] (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,080		
Capital recovery factor (16% of total turnkey costs	$ 4,320		
Total capital charges		$ 5,400	
TOTAL ANNUALIZED COSTS			$ 472

---

[a] Energy usage is described in Section 5.

TABLE A-3. ESTIMATED INCREMENTAL CAPITAL COSTS FOR STAGED COMBUSTION ON A NEW 59 MW PULVERIZED COAL-FIRED BOILER[a]

Equipment cost			
Basic equipment (includes freight)	______		
Required auxiliaries	______		
Total equipment cost	$26,000		
Installation costs, direct			
Foundations and supports	______		
Ductwork	______		
Stack	______		
Piping	______		
Insulation	______		
Painting	______		
Electrical	______		
Total installation cost	$12,000		
Total Direct Costs (equipment + installation)		$ 38,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 7,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 47,000	
Land		--	
Working capital (25% of total direct operating costs)[b]		$ 4,450	
GRAND TOTAL (turnkey + land + working capital)			$ 51,450

---

[a] Costs are engineering estimates based on References 4-1 and 4-10 through 4-13.
[b] From Annual Cost Table (see following table).

TABLE A-4. ESTIMATED INCREMENTAL ANNUAL COSTS FOR STAGED COMBUSTION ON A NEW 59 MW PULVERIZED COAL-FIRED BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 2,250		
Replacement parts			
Electricity -- fan	$12,612		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 2,953		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 17,817	
Overhead			
Payroll (30% of direct labor)	--		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,880		
Capital recovery factor (16% of total turnkey costs	$ 7,520		
Total capital charges		$ 9,400	
TOTAL ANNUALIZED COSTS			$ 27,217

---

[a] Energy usage is described in Section 5.

TABLE A-5. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW NO_x BURNERS (LNB) FOR A NEW 59 MW PULVERIZED COAL-FIRED BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 38,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 7,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 47,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 0	
GRAND TOTAL (turnkey + land + working capital)			$ 47,000

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5

[b] From Annual Cost Table (see following Table).

TABLE A-6. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 59 MW PULVERIZED COAL-FIRED BOILER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials			
Replacement parts			
Electricity			
Steam			
Cooling water			
Process water			
Fuel			
Waste disposal			
Chemicals			
Total direct cost		$ 17,800	
Overhead			
Payroll (30% of direct labor)	Included above		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,880		
Capital recovery factor (16% of total turnkey costs	$ 7,520		
Total capital charges		$ 9,400	
TOTAL ANNUALIZED COSTS			$ 27,200

---

[a] LNB operation is assumed to cost no more than staged combustion (see Sections 4 and 5).

TABLE A-7. ESTIMATED INCREMENTAL CAPITAL COSTS FOR AMMONIA INJECTION ON A NEW 59 MW PULVERIZED COAL-FIRED BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$235,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)	Included above		
Total Turnkey Costs (direct + indirect + contingencies		$237,000	
Land		--	
Working capital (25% of total direct operating costs)[b]		$ 8,000	
GRAND TOTAL (turnkey + land + working capital)			$245,000

---

[a] Ammonia injection costs are extrapolations from utility boiler data (References 4-4 and 4-5).
[b] From Annual Cost Table (see following table).

TABLE A-8. ESTIMATED INCREMENTAL ANNUAL COSTS FOR AMMONIA INJECTION ON A NEW 59 MW PULVERIZED COAL-FIRED BOILER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials			
Replacement parts			
Electricity			
Steam			
Cooling water			
Process water			
Fuel			
Waste disposal			
Chemicals			
Total direct cost		$ 31,084	
Overhead			
Payroll (30% of direct labor)	Included above		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 9,400		
Capital recovery factor (16% of total turnkey costs	$38,000		
Total capital charges		$ 47,400	
TOTAL ANNUALIZED COSTS			$ 78,484

---

[a] Ammonia injection costs are extrapolations from utility boiler data (References 4-4 and 4-5).

TABLE A-9. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 44 MW COAL-FIRED SPREADER STOKER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$13,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 4,000		
Total Direct Costs (equipment + installation)		$ 17,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 3,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 22,000	
Land		-	
Working capital (25% of total direct operating costs)[b]		0	
GRAND TOTAL (turnkey + land + working capital)			$ 22,000

---

[a] Costs are engineering estimates based on References 4-10 through 4-15.
[b] From Annual Cost Table (see following table).

TABLE A-10. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 44 MW COAL-FIRED SPREADER STOKER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,000		
Replacement parts			
Electricity	Negligible		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$(2,332)		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ (1,332)	
Overhead			
Payroll (30% of direct labor)			
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		$ (1,332)	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 880		
Capital recovery factor (16% of total turnkey costs	$ 3,520		
Total capital charges		$ 4,400	
TOTAL ANNUALIZED COSTS			$ 3,068

---

[a] Energy usage is described in Section 5.

TABLE A-11. ESTIMATED INCREMENTAL CAPITAL COSTS FOR STAGED COMBUSTION ON A NEW 44 MW COAL-FIRED SPREADER STOKER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$13,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 4,000		
Total Direct Costs (equipment + installation)		$ 17,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 3,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 22,000	
Land		--	
Working capital (25% of total direct operating costs)[b]		$ 200	
GRAND TOTAL (turnkey + land + working capital)			$ 22,000

---

[a] Costs are engineering estimates based on References 4-10 through 4-15.
[b] From Annual Cost Table (see following table).

TABLE A-12. ESTIMATED INCREMENTAL ANNUAL COSTS FOR STAGED COMBUSTION ON A NEW 44 MW COAL-FIRED SPREADER STOKER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,000		
Replacement parts			
Electricity	Negligible		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	0		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 1,000	
Overhead			
Payroll (30% of direct labor)	0		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 880		
Capital recovery factor (16% of total turnkey costs	$ 3,520		
Total capital charges		$ 4,400	
TOTAL ANNUALIZED COSTS			$ 5,400

---

[a] Energy usage is described in Section 5.

TABLE A-13. ESTIMATED INCREMENTAL CAPITAL COSTS FOR STAGED COMBUSTION ON A NEW 25 MW COAL-FIRED SPREADER STOKER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$10,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 3,000		
Total Direct Costs (equipment + installation)		$ 13,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 2,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 17,000	
Land		--	
Working capital (25% of total direct operating costs)[b]		$ 150	
GRAND TOTAL (turnkey + land + working capital)			$ 17,150

---

[a] Costs are engineering estimates based on References 4-10 through 4-15.

[b] From Annual Cost Table (see following table).

TABLE A-14. ESTIMATED INCREMENTAL ANNUAL COSTS FOR STAGED COMBUSTION ON A NEW 25 MW COAL-FIRED SPREADER STOKER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 750		
Replacement parts			
Electricity	Negligible		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	0		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 750	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 680		
Capital recovery factor (16% of total turnkey costs	$ 2,720		
Total capital charges		$ 3,400	
TOTAL ANNUALIZED COSTS			$ 4,150

---

[a] Energy usage is described in Section 5.

TABLE A-15. ESTIMATED INCREMENTAL CAPITAL COSTS FOR AMMONIA INJECTION ON A NEW 25 MW COAL-FIRED SPREADER STOKER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$100,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)	Included above		
Total Turnkey Costs (direct + indirect + contingencies		$102,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 3,400	
GRAND TOTAL (turnkey + land + working capital)			$ 10,540

---

[a] Ammonia injection costs are extrapolations from utility boiler data (References 4-4 and 4-5).

[b] From Annual Cost Table (see following table).

TABLE A-16. ESTIMATED INCREMENTAL ANNUAL COSTS FOR AMMONIA INJECTION ON A NEW 25 MW COAL-FIRED SPREADER STOKER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials			
Replacement parts			
Electricity			
Steam			
Cooling water			
Process water			
Fuel			
Waste disposal			
Chemicals			
Total direct cost		$ 13,625	
Overhead			
Payroll (30% of direct labor)	Included above		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 4,080		
Capital recovery factor (16% of total turnkey costs	$16,320		
Total capital charges		$ 20,400	
TOTAL ANNUALIZED COSTS			$ 34,025

---

[a] Ammonia injection costs are extrapolations from utility boiler data (References 4-4 and 4-5).

TABLE A-17. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 22 MW COAL-FIRED CHAIN GRATE STOKER[a]

Equipment cost			
Basic equipment (includes freight)	______		
Required auxiliaries	______		
Total equipment cost	$10,000		
Installation costs, direct			
Foundations and supports	______		
Ductwork	______		
Stack	______		
Piping	______		
Insulation	______		
Painting	______		
Electrical	______		
Total installation cost	$ 3,000		
Total Direct Costs (equipment + installation)		$ 13,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 2,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 17,000	
Land		______	
Working capital (25% of total direct operating costs)[b]		$ 0	
GRAND TOTAL (turnkey + land + working capital)			$ 17,000

---

[a] Costs are engineering estimates based on References 4-10 through 4-15.
[b] From Annual Cost Table (see following table).

TABLE A-18. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 22 MW COAL-FIRED CHAIN GRATE STOKER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,000		
Replacement parts			
Electricity	small		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$(2,286)		
Waste disposal	0		
Chemicals	0		
Total direct cost		$(1,286)	
Overhead			
Payroll (30% of direct labor)			
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 680		
Capital recovery factor (16% of total turnkey costs	$ 2,720		
Total capital charges		$ 3,400	
TOTAL ANNUALIZED COSTS			$ 2,114

---

[a] Energy usage is discussed in Section 5.

TABLE A-19. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 9 MW COAL-FIRED UNDERFEED STOKER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$ 8,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 2,000		
Total Direct Costs (equipment + installation)		$ 10,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 2,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 14,000	
Land		--	
Working capital (25% of total direct operating costs)[b]		$ 0	
GRAND TOTAL (turnkey + land + working capital)			$ 14,000

---

[a] Costs are engineering estimates based on References 4-10 through 4-15.
[b] From Annual Cost Table (see following table).

TABLE A-20. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 9 MW COAL-FIRED UNDERFEED STOKER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 600		
Replacement parts			
Electricity	small		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ (927)		
Waste disposal			
Chemicals			
Total direct cost		$ (327)	
Overhead			
Payroll (30% of direct labor)			
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 560		
Capital recovery factor (16% of total turnkey costs	$ 2,240		
Total capital charges		$ 2,800	
TOTAL ANNUALIZED COSTS			$ 2,473

---

[a] Energy usage is discussed in Section 5.

TABLE A-21. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 4.4 MW RESIDUAL OIL-FIRED FIRETUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)	______		
Required auxiliaries	______		
Total equipment cost	$ 5,000		
Installation costs, direct			
Foundations and supports	______		
Ductwork	______		
Stack	______		
Piping	______		
Insulation	______		
Painting	______		
Electrical	______		
Total installation cost	$ 1,000		
Total Direct Costs (equipment + installation)		$ 6,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 1,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 9,000	
Land		______	
Working capital (25% of total direct operating costs)[b]		$ 0	
GRAND TOTAL (turnkey + land + working capital)			$ 9,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-22. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 4.4 MW RESIDUAL OIL-FIRED FIRETUBE BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor	0		
Maintenance materials	$ 350		
Replacement parts			
Electricity	small		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ (770)		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ (420)	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 360		
Capital recovery factor (16% of total turnkey costs	$ 1,440		
Total capital charges		$ 1,800	
TOTAL ANNUALIZED COSTS			$ 1,380

---

[a] Energy usage is discussed in Section 5.

TABLE A-23. ESTIMATED INCREMENTAL CAPITAL COSTS FOR STAGED COMBUSTION ON A NEW 4.4 MW RESIDUAL OIL-FIRED FIRETUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$ 7,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 7,000		
Total Direct Costs (equipment + installation)		$ 14,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 3,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 19,000	
Land		--	
Working capital (25% of total direct operating costs)[b]		$ 1,435	
GRAND TOTAL (turnkey + land + working capital)			$ 20,435

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-24. ESTIMATED INCREMENTAL ANNUAL COSTS FOR STAGED COMBUSTION ON A NEW 4.4 MW RESIDUAL OIL-FIRED FIRETUBE BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor	$ 850		
Maintenance materials			
Replacement parts			
Electricity	$ 631		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 857		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 2,338	
Overhead			
Payroll (30% of direct labor)	--		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 760		
Capital recovery factor (16% of total turnkey costs	$ 3,040		
Total capital charges		$ 3,800	
TOTAL ANNUALIZED COSTS			$ 6,138

---

[a] Energy usage is discussed in Section 5.

TABLE A-25. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW NO$_x$ BURNERS (LNB) ON A NEW 4.4 MW RESIDUAL OIL-FIRED FIRETUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 14,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 3,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 19,000	
Land			
Working capital (25% of total direct operating costs)[b]			
GRAND TOTAL (turnkey + land + working capital)			$ 19,000

---

[a] LNB is assumed to cost no more than staged combustion and most likely will cost less (see Sections 4 and 5).

[b] From Annual Cost Table (see following table).

TABLE A-26. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW NO$_x$ BURNERS (LNB) ON A NEW 4.4 MW RESIDUAL OIL-FIRED FIRETUBE BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 850		
Replacement parts			
Electricity	Depends if pressure drop changes		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	Probably small		
Waste disposal			
Chemicals			
Total direct cost		$ 2,338 (using same value as used for staged combustion)	
Overhead			
Payroll (30% of direct labor)			
Plant (26% of labor, parts & maint.)			
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 720		
Capital recovery factor (16% of total turnkey costs	$ 3,080		
Total capital charges		$ 3,800	
TOTAL ANNUALIZED COSTS			$ 6,138

---

[a] LNB operation is assumed to cost no more than staged combustion and will probably cost less (see Sections 4 and 5).

TABLE A-27. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 44 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$10,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 3,000		
Total Direct Costs (equipment + installation)		$ 13,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 2,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 17,000	
Land			
Working capital (25% of total direct operating costs)[b]		0	
GRAND TOTAL (turnkey + land + working capital)			$ 17,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-28. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 44 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor	$ 750		
Maintenance materials			
Replacement parts			
Electricity	Negligible		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$(20,734)		
Waste disposal	0		
Chemicals	0		
Total direct cost		$(19,984)	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 680		
Capital recovery factor (16% of total turnkey costs	$ 2,720		
Total capital charges		$ 3,400	
TOTAL ANNUALIZED COSTS			$(16,584)

---

[a] Energy usage is described in Section 5.

TABLE A-29. ESTIMATED INCREMENTAL CAPITAL COSTS FOR STAGED COMBUSTION ON A NEW 44 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$15,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$10,000		
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 5,329	
GRAND TOTAL (turnkey + land + working capital)			$ 37,329

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-30. ESTIMATED INCREMENTAL ANNUAL COSTS FOR STAGED COMBUSTION ON A NEW 44 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,500		
Replacement parts			
Electricity	$ 9,250		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$10,566		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 21,317	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		--	
By-product credits		(　　)	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,280		
Capital recovery factor (16% of total turnkey costs	$ 5,120		
Total capital charges		$ 6,400	
TOTAL ANNUALIZED COSTS			$ 31,317

---

[a] Energy usage is described in Section 5.

TABLE A-31. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 44 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land			
Working capital (25% of total direct operating costs)[b]			
GRAND TOTAL (turnkey + land + working capital)			$ 32,000

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).
[b] From Annual Cost Table (see following table).

TABLE A-32. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 44 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,500		
Replacement parts			
Electricity	?		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	?		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 21,000	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,280		
Capital recovery factor (16% of total turnkey costs	$ 5,120		
Total capital charges		$ 6,400	
TOTAL ANNUALIZED COSTS			$ 27,400

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).

TABLE A-33. ESTIMATED INCREMENTAL CAPITAL COSTS FOR AMMONIA INJECTION ON A NEW 44 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)	______		
Required auxiliaries	______		
Total equipment cost	______		
Installation costs, direct			
Foundations and supports	______		
Ductwork	______		
Stack	______		
Piping	______		
Insulation	______		
Painting	______		
Electrical	______		
Total installation cost	______		
Total Direct Costs (equipment + installation)		$180,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		Included above	
Total Turnkey Costs (direct + indirect + contingencies		$182,000	
Land		______	
Working capital (25% of total direct operating costs)[b]		$ 6,000	
GRAND TOTAL (turnkey + land + working capital)			$188,000

---

[a] Ammonia injection costs are extrapolated from utility boiler data (References 4-4 and 4-5).

[b] From Annual Cost Table (see following table).

TABLE A-34. ESTIMATED INCREMENTAL ANNUAL COSTS FOR AMMONIA INJECTION ON A NEW 44 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials			
Replacement parts			
Electricity			
Steam			
Cooling water			
Process water			
Fuel			
Waste disposal			
Chemicals			
Total direct cost		$ 24,000	
Overhead			
Payroll (30% of direct labor)	Included above		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 7,200		
Capital recovery factor (16% of total turnkey costs	$28,800		
Total capital charges		$ 36,000	
TOTAL ANNUALIZED COSTS			$ 60,000

---

[a] Ammonia injection costs are extrapolated from utility boiler data (References 4-4 and 4-5).

TABLE A-35. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 4.4 MW DISTILLATE OIL-FIRED FIRETUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$ 5,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 1,000		
Total Direct Costs (equipment + installation)		$ 6,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 1,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 9,000	
Land		--	
Working capital (25% of total direct operating costs)[b]		0	
GRAND TOTAL (turnkey + land + working capital)			$ 9,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-36. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 4.4 MW DISTILLATE OIL-FIRED FIRETUBE BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 350		
Replacement parts			
Electricity	Negligible		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ (870)		
Waste disposal			
Chemicals			
Total direct cost		$ (520)	
Overhead			
Payroll (30% of direct labor)	--		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 360		
Capital recovery factor (16% of total turnkey costs	$ 1,440		
Total capital charges		$ 1,800	
TOTAL ANNUALIZED COSTS			$ 1,280

---

[a] Energy usage is described in Section 5.

TABLE A-37. ESTIMATED INCREMENTAL CAPITAL COSTS FOR FLUE GAS RECIRCULATION ON A NEW 4.4 MW DISTILLATE OIL-FIRED FIRETUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$ 9,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 5,000		
Total Direct Costs (equipment + installation)		$ 14,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 3,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 19,000	
Land		--	
Working capital (25% of total direct operating costs)[b]		$ 875	
GRAND TOTAL (turnkey + land + working capital)			$ 19,875

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-38. ESTIMATED INCREMENTAL ANNUAL COSTS DUE TO FLUE GAS RECIRCULATION ON A NEW 4.4 MW DISTILLATE OIL-FIRED FIRETUBE BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 850		
Replacement parts			
Electricity - Fan	$ 1,733		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 914		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 3,497	
Overhead			
Payroll (30% of direct labor)	--		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 760		
Capital recovery factor (16% of total turnkey costs	$ 3,040		
Total capital charges		$ 3,800	
TOTAL ANNUALIZED COSTS			$ 7,297

---

[a] Energy usage is described in Section 5.

TABLE A-39. ESTIMATED INCREMENTAL CAPITAL COSTS OF LOW NO_x BURNERS (LNB) ON A NEW 4.4 MW DISTILLATE OIL-FIRED FIRETUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 14,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 3,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 19,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 500	
GRAND TOTAL (turnkey + land + working capital)			$ 19,500

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).
[b] From Annual Cost Table (see following table)

TABLE A-40. ESTIMATED INCREMENTAL ANNUAL COSTS OF LOW NO_x BURNERS (LNB) ON A NEW 4.4 MW DISTILLATE OIL-FIRED FIRETUBE BOILER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials			
Replacement parts			
Electricity			
Steam			
Cooling water			
Process water			
Fuel			
Waste disposal			
Chemicals			
Total direct cost		$ 1,900	
Overhead			
Payroll (30% of direct labor)			
Plant (26% of labor, parts & maint.)			
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)			
Capital recovery factor (16% of total turnkey costs			
Total capital charges		$ 3,400	
TOTAL ANNUALIZED COSTS			$ 5,300

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).

TABLE A-41. ESTIMATED INCREMENTAL CAPITAL COSTS FOR FLUE GAS RECIRCULATION ON A NEW 29 MW DISTILLATE OIL-FIRED FIRETUBE BOILER WITHOUT AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$13,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 7,000		
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 6,000	
GRAND TOTAL (turnkey + land + working capital)			$ 32,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-42. ESTIMATED INCREMENTAL ANNUAL COSTS FOR FLUE GAS RECIRCULATION ON A NEW 29 MW DISTILLATE OIL-FIRED FIRETUBE BOILER WITHOUT AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor Maintenance materials Replacement parts	$ 1,200		
Electricity - Fan	$14,718		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 8,494		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 24,412	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,040		
Capital recovery factor (16% of total turnkey costs	$ 4,160		
Total capital charges		$ 5,200	
TOTAL ANNUALIZED COSTS			$ 29,612

---

[a] Energy usage is described in Section 5.

TABLE A-43. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITHOUT AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 3,750	
GRAND TOTAL (turnkey + land + working capital)			$ 29,750

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).
[b] From Annual Cost Table (see following table).

TABLE A-44. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITHOUT AN AIR PREHEATER[a]

Direct cost			
Direct labor	______		
Supervision	______		
Maintenance labor	______		
Maintenance materials	______		
Replacement parts	______		
Electricity	______		
Steam	______		
Cooling water	______		
Process water	______		
Fuel	______		
Waste disposal	______		
Chemicals	______		
Total direct cost		$ 15,000	
Overhead			
Payroll (30% of direct labor)	______		
Plant (26% of labor, parts & maint.)	______		
Total overhead cost		______	
By-product credits		(______)	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	______		
Capital recovery factor (16% of total turnkey costs	______		
Total capital charges		$ 4,800	
TOTAL ANNUALIZED COSTS			$ 19,800

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).

TABLE A-45. ESTIMATED INCREMENTAL CAPITAL COSTS FOR STAGED COMBUSTION ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITHOUT AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$13,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 7,000		
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 3,775	
GRAND TOTAL (turnkey + land + working capital)			$ 29,775

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-46. ESTIMATED INCREMENTAL ANNUAL COSTS OF STAGED COMBUSTION ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITHOUT AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,200		
Replacement parts			
Electricity - Fan	$ 6,307		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 7,597		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 15,103	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,080		
Capital recovery factor (16% of total turnkey costs	$ 4,120		
Total capital charges		$ 5,200	
TOTAL ANNUALIZED COSTS			$ 20,303

---

[a] Energy usage is described in Section 5.

TABLE A-47. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW EXCESS AIR ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$ 8,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 2,000		
Total Direct Costs (equipment + installation)		$ 10,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 2,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 14,000	
Land		--	
Working capital (25% of total direct operating costs)[b]		0	
GRAND TOTAL (turnkey + land + working capital)			$ 14,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-48. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 600		
Replacement parts			
Electricity	Negligible		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$(4,018)		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ (3,418)	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 560		
Capital recovery factor (16% of total turnkey costs	$ 2,240		
Total capital charges		$ 2,800	
TOTAL ANNUALIZED COSTS			$ (618)

---

[a] Energy usage is described in Section 5.

TABLE A-49. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	0		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	0		
Total Direct Costs (equipment + installation)		0	
Installation costs, indirect			
Engineering (10% of direct costs)			
Construction and field expense (10% of direct costs)			
Construction fees (10% of direct costs)			
Start-up (2% of direct costs)			
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)			
Total Turnkey Costs (direct + indirect + contingencies		$ 2,000	
Land			
Working capital (25% of total direct operating costs)[a]		$ 5,000	
GRAND TOTAL (turnkey + land + working capital)			$ 7,000

---

[a] From Annual Cost Table (see following table).

TABLE A-50. ESTIMATED INCREMENTAL ANNUAL COSTS FOR REDUCED AIR PREHEAT ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor	0		
Maintenance materials	0		
Replacement parts	0		
Electricity	0		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$23,388		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 23,388	
Overhead			
Payroll (30% of direct labor)	--		
Plant (26% of labor, parts & maint.)	--		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 80		
Capital recovery factor (16% of total turnkey costs	$ 320		
Total capital charges		$ 400	
TOTAL ANNUALIZED COSTS			$ 23,788

---

[a] Energy usage is described in Section 5.

TABLE A-51. ESTIMATED INCREMENTAL CAPITAL COSTS FOR FLUE GAS RECIRCULATION ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$13,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 7,000		
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[a]		$ 6,000	
GRAND TOTAL (turnkey + land + working capital)			$ 32,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-52. ESTIMATED INCREMENTAL ANNUAL COSTS FOR FLUE GAS RECIRCULATION ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor Maintenance materials Replacement parts	$ 1,200		
Electricity	$14,718		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 8,494		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 24,412	
Overhead			
Payroll (30% of direct labor)	--		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,040		
Capital recovery factor (16% of total turnkey costs	$ 4,160		
Total capital charges		$ 5,200	
TOTAL ANNUALIZED COSTS			$ 29,612

---

[a] Energy usage is described in Section 5.

TABLE A-53. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[a]		$ 3,750	
GRAND TOTAL (turnkey + land + working capital)			$ 29,750

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).
[b] From Annual Cost Table (see following table).

TABLE A-54. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials			
Replacement parts			
Electricity			
Steam			
Cooling water			
Process water			
Fuel			
Waste disposal			
Chemicals			
Total direct cost		$ 15,000	
Overhead			
Payroll (30% of direct labor)			
Plant (26% of labor, parts & maint.)			
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)			
Capital recovery factor (16% of total turnkey costs			
Total capital charges		$ 5,200	
TOTAL ANNUALIZED COSTS			$ 20,200

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).

TABLE A-55. ESTIMATED INCREMENTAL CAPITAL COSTS FOR STAGED COMBUSTION ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$13,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 7,000		
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[a]		$ 3,778	
GRAND TOTAL (turnkey + land + working capital)			$ 29,778

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-56. ESTIMATED INCREMENTAL ANNUAL COSTS FOR STAGED COMBUSTION ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,200		
Replacement parts			
Electricity - Fan	$ 6,307		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 7,605		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 15,112	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,040		
Capital recovery factor (16% of total turnkey costs	$ 4,160		
Total capital charges		$ 5,200	
TOTAL ANNUALIZED COSTS			$ 20,312

---

[a] Energy usage is described in Section 5.

TABLE A-57. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT AND FLUE GAS RECIRCULATION ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$13,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 7,000		
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[a]		$ 12,000	
GRAND TOTAL (turnkey + land + working capital)			$ 38,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table)

TABLE A-58. ESTIMATED INCREMENTAL ANNUAL COSTS OF REDUCED AIR PREHEAT AND FLUE GAS RECIRCULATION ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,200		
Replacement parts			
Electricity - Fan	$14,718		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$31,757		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 47,675	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,040		
Capital recovery factor (16% of total turnkey costs	$ 4,160		
Total capital charges		$ 5,200	
TOTAL ANNUALIZED COSTS			$ 52,875

---

[a] Energy usage is described in Section 5.

TABLE A-59. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT AND LOW NO_x BURNERS ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital '25% of total direct operating costs)[a]		$ 4,000	
GRAND TOTAL (turnkey + land + working capital)			$ 30,000

---

[a] LNB operation is assumed to cost no more than staged combustion (see Sections 4 and 5).

[b] From Annual Cost Table (see following table).

TABLE A-60. ESTIMATED INCREMENTAL ANNUAL COSTS FOR REDUCED AIR PREHEAT AND LOW NO_x BURNERS ON A NEW 29 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials			
Replacement parts			
Electricity - Fan			
Steam			
Cooling water			
Process water			
Fuel			
Waste disposal			
Chemicals			
Total direct cost		$ 38,000	
Overhead			
Payroll (30% of direct labor)			
Plant (26% of labor, parts & maint.)			
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)			
Capital recovery factor (16% of total turnkey costs			
Total capital charges		$ 5,200	
TOTAL ANNUALIZED COSTS			$ 43,200

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).

TABLE A-61. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITHOUT AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$ 8,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 2,000		
Total Direct Costs (equipment + installation)		$ 10,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 2,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 14,000	
Land			
Working capital (25% of total direct operating costs)[a]		0	
GRAND TOTAL (turnkey + land + working capital)			$ 14,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-62. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITHOUT AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 600		
Replacement parts			
Electricity	Negligible		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$(4,990)		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ (4,390)	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 560		
Capital recovery factor (16% of total turnkey costs	$ 2,240		
Total capital charges		$ 2,800	
TOTAL ANNUALIZED COSTS			$ (1,590)

---

[a] Energy usage is described in Section 5.

TABLE A-63. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT OPERATION ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	0		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	0		
Total Direct Costs (equipment + installation)		0	
Installation costs, indirect			
Engineering (10% of direct costs)			
Construction and field expense (10% of direct costs)			
Construction fees (10% of direct costs)			
Start-up (2% of direct costs)			
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)			
Total Turnkey Costs (direct + indirect + contingencies		$ 2,000	
Land			
Working capital (25% of total direct operating costs)[a]		$ 5,000	
GRAND TOTAL (turnkey + land + working capital)			$ 7,000

---

[a] From Annual Cost Table (see following table).

TABLE A-64. ESTIMATED INCREMENTAL ANNUAL COSTS DUE TO REDUCED AIR PREHEAT OPERATION FOR A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	0		
Replacement parts			
Electricity	Possible small savings		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$20,330		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 20,330	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	-		
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 80		
Capital recovery factor (16% of total turnkey costs	$ 320		
Total capital charges		$ 400	
TOTAL ANNUALIZED COSTS			$ 20,730

---

[a] Energy used by RAP is described in Section 5.

TABLE A-65. ESTIMATED INCREMENTAL CAPITAL COSTS FOR FLUE GAS RECIRCULATION ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$13,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 7,000		
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 5,000	
GRAND TOTAL (turnkey + land + working capital)			$ 31,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-66. ESTIMATED INCREMENTAL ANNUAL COSTS FOR FLUE GAS RECIRCULATION ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,200		
Replacement parts			
Electricity - Fan	$14,717		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 5,672		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 21,589	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,040		
Capital recovery factor (16% of total turnkey costs	$ 4,160		
Total capital charges		$ 5,200	
TOTAL ANNUALIZED COSTS			$ 26,784

---

[a] Energy usage is described in Section 5.

TABLE A-67. ESTIMATED INCREMENTAL CAPITAL COSTS FOR STAGED COMBUSTION ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$13,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 7,000		
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 3,000	
GRAND TOTAL (turnkey + land + working capital)			$ 29,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-68. ESTIMATED INCREMENTAL ANNUAL COSTS FOR STAGED COMBUSTION ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,200		
Replacement parts			
Electricity - Fan	$ 6,307		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 4,907		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 12,414	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,040		
Capital recovery factor (16% of total turnkey costs	$ 4,160		
Total capital charges		$ 5,200	
TOTAL ANNUALIZED COSTS			$ 17,614

---

[a] Energy usage is described in Section 5.

TABLE A-69. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW NO^x BURNERS (LNB) ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 3,000	
GRAND TOTAL (turnkey + land + working capital)			$ 29,000

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).

[b] From Annual Cost Table (see following table).

TABLE A-70. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials			
Replacement parts			
Electricity			
Steam			
Cooling water			
Process water			
Fuel			
Waste disposal			
Chemicals			
Total direct cost		$ 12,000	
Overhead			
Payroll (30% of direct labor)			
Plant (26% of labor, parts & maint.)			
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)			
Capital recovery factor (16% of total turnkey costs			
Total capital charges		$ 5,200	
TOTAL ANNUALIZED COSTS			$ 17,200

---

[a] LNB operation is assumed to cost no more than staged combustion (see Sections 4 and 5).

TABLE A-71. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT AND STAGED COMBUSTION ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$13,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 7,000		
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 8,000	
GRAND TOTAL (turnkey + land + working capital)			$ 34,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-72. ESTIMATED INCREMENTAL ANNUAL COSTS FOR REDUCED AIR PREHEAT AND STAGED COMBUSTION ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,200		
Replacement parts			
Electricity - Fan	$ 6,307		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$25,416		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 32,923	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,080		
Capital recovery factor (16% of total turnkey costs	$ 4,160		
Total capital charges		$ 5,200	
TOTAL ANNUALIZED COSTS			$ 38,123

---

[a] Energy use is discussed in Section 5).

TABLE A-73. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT AND FLUE GAS RECIRCULATION ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$13,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 7,000		
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 10,000	
GRAND TOTAL (turnkey + land + working capital)			$ 36,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-74. ESTIMATED INCREMENTAL ANNUAL COSTS FOR REDUCED AIR PREHEAT AND FLUE GAS RECIRCULATION ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,200		
Replacement parts			
Electricity - Fan	$14,717		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$26,001		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 41,918	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,080		
Capital recovery factor (16% of total turnkey costs	$ 4,120		
Total capital charges		$ 5,200	
TOTAL ANNUALIZED COSTS			$ 47,118

---

[a] Energy use is discussed in Section 5).

TABLE A-75. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT AND LOW NO$_x$ BURNERS ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 20,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 4,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 26,000	
Land			
Working capital (25% of total direct operating costs)[b]			
GRAND TOTAL (turnkey + land + working capital)			

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).

[b] From Annual Cost Table (see following table).

TABLE A-76. ESTIMATED INCREMENTAL ANNUAL COSTS FOR REDUCED AIR PREHEAT (RAP) AND LOW NO_x BURNERS (LNB) ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	———		
Supervision	———		
Maintenance labor	———		
Maintenance materials	———		
Replacement parts	———		
Electricity - Fan	———		
Steam	———		
Cooling water	———		
Process water	———		
Fuel	$20,330 RAP		
Waste disposal	———		
Chemicals	———		
Total direct cost		$ 32,330	
Overhead			
Payroll (30% of direct labor)	Included above		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		———	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 960		
Capital recovery factor (16% of total turnkey costs	$ 3,840		
Total capital charges		$ 4,800	
TOTAL ANNUALIZED COSTS			$ 37,130

---

[a] LNB is assumed to cost no more than staged combustion and RAP energy use is described in Section 5.

TABLE A-77. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT AND NH_3 INJECTION FOR A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$116,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		Included above	
Total Turnkey Costs (direct + indirect + contingencies		$118,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 9,000	
GRAND TOTAL (turnkey + land + working capital)			$127,000

---

[a] NH_3 injection costs are extrapolated from utility boiler data (References 4-4 and 4-5).

[b] From Annual Cost Table (see following table).

TABLE A-78. ESTIMATED INCREMENTAL ANNUAL COSTS FOR REDUCED AIR PREHEAT (RAP) AND NH_3 INJECTION ON A NEW 29 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials	$15,831 NH_3 injection		
Replacement parts			
Electricity - Fan			
Steam			
Cooling water			
Process water			
Fuel	$20,330 RAP		
Waste disposal			
Chemicals			
Total direct cost		$ 36,161	
Overhead			
Payroll (30% of direct labor)	Included above		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 4,720		
Capital recovery factor (16% of total turnkey costs	$18,880		
Total capital charges		$ 23,600	
TOTAL ANNUALIZED COSTS			$ 59,361

---

[a] Ammonia injection costs are extrapolated from utility boiler data (References 4-4 and 4-5) and RAP energy use is from Section 5.

TABLE A-79. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 117 MW PULVERIZED COAL-FIRED BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$25,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$10,000		
Total Direct Costs (equipment + installation)		$ 35,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 7,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 44,000	
Land			
Working capital (25% of total direct operating costs)[b]		0	
GRAND TOTAL (turnkey + land + working capital)			$ 44,000

---

[a] Costs are engineering estimates based on References 4-1 and 4-10 through 4-13.
[b] From Annual Cost Table (see next table).

TABLE A-80. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 117 MW PULVERIZED COAL-FIRED BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 2,100		
Replacement parts			
Electricity	Negligible		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	($12,356)		
Waste disposal	0		
Chemicals	0		
Total direct cost		$(10,256)	
Overhead			
Payroll (30% of direct labor)	--		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,760		
Capital recovery factor (16% of total turnkey costs	$ 7,040		
Total capital charges		$ 8,800	
TOTAL ANNUALIZED COSTS			$ 1,456

---

[a] Energy usage is described in Section 5.

TABLE A-81. ESTIMATED INCREMENTAL CAPITAL COSTS FOR STAGED COMBUSTION ON A NEW 117 MW PULVERIZED COAL-FIRED BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$39,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$24,000		
Total Direct Costs (equipment + installation)		$ 63,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 13,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 78,000	
Land		--	
Working capital (25% of total direct operating costs)[b]		$ 9,000	
GRAND TOTAL (turnkey + land + working capital)			$ 87,000

---

[a] Costs are engineering estimates based on References 4-1 and 4-10 through 4-13.
[b] From Annual Cost Table (see following table).

TABLE A-82. ESTIMATED INCREMENTAL ANNUAL COSTS FOR STAGED COMBUSTION ON A NEW 117 MW PULVERIZED COAL-FIRED BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 3,900		
Replacement parts			
Electricity -- fan	$25,224		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 5,906		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 35,030	
Overhead			
Payroll (30% of direct labor)	--		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		(　　)	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 3,120		
Capital recovery factor (16% of total turnkey costs	$12,480		
Total capital charges		$ 15,600	
TOTAL ANNUALIZED COSTS			$ 50,630

---

[a] Energy usage is described in Section 5.

TABLE A-83. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW NO_x BURNERS (LNB) FOR A NEW 117 MW PULVERIZED COAL-FIRED BOILER[a]

Equipment cost			
Basic equipment (includes freight)	———		
Required auxiliaries	———		
Total equipment cost	———		
Installation costs, direct			
Foundations and supports	———		
Ductwork	———		
Stack	———		
Piping	———		
Insulation	———		
Painting	———		
Electrical	———		
Total installation cost	———		
Total Direct Costs (equipment + installation)		$ 63,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 13,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 78,000	
Land		———	
Working capital (25% of total direct operating costs)[b]		$ 0	
GRAND TOTAL (turnkey + land + working capital)			$ 78,000

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5

[b] From Annual Cost Table (see following Table).

TABLE A-84. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 117 MW PULVERIZED COAL-FIRED BOILER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials			
Replacement parts			
Electricity			
Steam			
Cooling water			
Process water			
Fuel			
Waste disposal			
Chemicals			
Total direct cost		$ 35,000	
Overhead			
Payroll (30% of direct labor)	Included above		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 3,120		
Capital recovery factor (16% of total turnkey costs	$12,480		
Total capital charges		$ 15,600	
TOTAL ANNUALIZED COSTS			$ 50,630

---

[a] LNB operation is assumed to cost no more than staged combustion (see Sections 4 and 5).

TABLE A-85. ESTIMATED INCREMENTAL CAPITAL COSTS FOR AMMONIA INJECTION ON A NEW 117 MW PULVERIZED COAL-FIRED BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$470,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)	Included above		
Total Turnkey Costs (direct + indirect + contingencies		$472,000	
Land		--	
Working capital (25% of total direct operating costs)[b]		$ 16,000	
GRAND TOTAL (turnkey + land + working capital)			$488,000

---

[a] Ammonia injection costs are extrapolations from utility boiler data (References 4-4 and 4-5).

[b] From Annual Cost Table (see following table).

TABLE A-86. ESTIMATED INCREMENTAL ANNUAL COSTS FOR AMMONIA INJECTION ON A NEW 117 MW PULVERIZED COAL-FIRED BOILER[a]

Direct cost			
Direct labor	______		
Supervision	______		
Maintenance labor	______		
Maintenance materials	______		
Replacement parts	______		
Electricity	______		
Steam	______		
Cooling water	______		
Process water	______		
Fuel	______		
Waste disposal	______		
Chemicals	______		
Total direct cost		$ 62,168	
Overhead			
Payroll (30% of direct labor)	Included above		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		______	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$18,800		
Capital recovery factor (16% of total turnkey costs	$76,000		
Total capital charges		$ 94,800	
TOTAL ANNUALIZED COSTS			$156,968

---

[a] Ammonia injection costs are extrapolations from utility boiler data (References 4-4 and 4-5).

TABLE A-87. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 8.8 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$ 7,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 2,000		
Total Direct Costs (equipment + installation)		$ 9,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 1,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 12,000	
Land			
Working capital (25% of total direct operating costs)[b]		0	
GRAND TOTAL (turnkey + land + working capital)			$ 12,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-88. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 8.8 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 500		
Replacement parts			
Electricity	Negligible		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ (4,147)		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ (3,647)	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 480		
Capital recovery factor (16% of total turnkey costs	$ 1,920		
Total capital charges		$ 2,400	
TOTAL ANNUALIZED COSTS			$ (1,247)

---

[a] Energy usage is described in Section 5.

TABLE A-89. ESTIMATED INCREMENTAL CAPITAL COSTS FOR STAGED COMBUSTION ON A NEW 8.8 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$10,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 7,000		
Total Direct Costs (equipment + installation)		$ 17,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 3,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 22,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 2,000	
GRAND TOTAL (turnkey + land + working capital)			$ 24,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-90. ESTIMATED INCREMENTAL ANNUAL COSTS FOR STAGED COMBUSTION ON A NEW 8.8 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,000		
Replacement parts			
Electricity	$ 1,650		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 2,113		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 4,763	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 880		
Capital recovery factor (16% of total turnkey costs	$ 3,520		
Total capital charges		$ 4,400	
TOTAL ANNUALIZED COSTS			$ 9,163

---

[a] Energy usage is described in Section 5.

TABLE A-91. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 8.8 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 17,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 3,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 22,000	
Land			
Working capital (25% of total direct operating costs)[b]			
GRAND TOTAL (turnkey + land + working capital)			$ 22,000

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).
[b] From Annual Cost Table (see following table).

TABLE A-92. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 8.8 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,000		
Replacement parts			
Electricity	?		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	?		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 4,500	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 880		
Capital recovery factor (16% of total turnkey costs	$ 3,520		
Total capital charges		$ 4,400	
TOTAL ANNUALIZED COSTS			$ 8,900

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).

TABLE A-93. ESTIMATED INCREMENTAL CAPITAL COSTS FOR AMMONIA INJECTION ON A NEW 8.8 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 70,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		Included above	
Total Turnkey Costs (direct + indirect + contingencies		$ 72,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 1,000	
GRAND TOTAL (turnkey + land + working capital)			$ 73,000

---

[a] Ammonia injection costs are extrapolated from utility boiler data (References 4-4 and 4-5).

[b] From Annual Cost Table (see following table).

TABLE A-94. ESTIMATED INCREMENTAL ANNUAL COSTS FOR AMMONIA INJECTION ON A NEW 8.8 MW RESIDUAL OIL-FIRED WATERTUBE BOILER[a]

Direct cost			
Direct labor	____		
Supervision	____		
Maintenance labor	____		
Maintenance materials	____		
Replacement parts	____		
Electricity	____		
Steam	____		
Cooling water	____		
Process water	____		
Fuel	____		
Waste disposal	____		
Chemicals	____		
Total direct cost		$ 5,000	
Overhead			
Payroll (30% of direct labor)	Included above		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		____	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 2880		
Capital recovery factor (16% of total turnkey costs	$11,520		
Total capital charges		$ 14,400	
TOTAL ANNUALIZED COSTS			$ 19,400

---

[a] Ammonia injection costs are extrapolated from utility boiler data (References 4-4 and 4-5).

TABLE A-95. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW EXCESS AIR ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$10,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$ 3,000		
Total Direct Costs (equipment + installation)		$ 13,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 2,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 17,000	
Land		--	
Working capital (25% of total direct operating costs)[b]		0	
GRAND TOTAL (turnkey + land + working capital)			$ 17,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-96. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW EXCESS AIR OPERATION ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 750		
Replacement parts			
Electricity	Negligible		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$(6,027)		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ (5,277)	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 680		
Capital recovery factor (16% of total turnkey costs	$ 2,720		
Total capital charges		$ 3,400	
TOTAL ANNUALIZED COSTS			$ (1877)

---

[a] Energy usage is described in Section 5.

TABLE A-97. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	0		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	0		
Total Direct Costs (equipment + installation)		0	
Installation costs, indirect			
Engineering (10% of direct costs)			
Construction and field expense (10% of direct costs)			
Construction fees (10% of direct costs)			
Start-up (2% of direct costs)			
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)			
Total Turnkey Costs (direct + indirect + contingencies		$ 2,000	
Land			
Working capital (25% of total direct operating costs)[a]		$ 8,770	
GRAND TOTAL (turnkey + land + working capital)			$ 10,770

---

[a] From Annual Cost Table (see following table).

TABLE A-98. ESTIMATED INCREMENTAL ANNUAL COSTS FOR REDUCED AIR PREHEAT ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor	0		
Maintenance materials	0		
Replacement parts	0		
Electricity	0		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$35,082		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 35,082	
Overhead			
Payroll (30% of direct labor)	--		
Plant (26% of labor, parts & maint.)	--		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 80		
Capital recovery factor (16% of total turnkey costs	$ 320		
Total capital charges		$ 400	
TOTAL ANNUALIZED COSTS			$ 35,482

---

[a] Energy usage is described in Section 5.

TABLE A-99. ESTIMATED INCREMENTAL CAPITAL COSTS FOR FLUE GAS RECIRCULATION ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)	______		
Required auxiliaries	______		
Total equipment cost	$15,000		
Installation costs, direct			
Foundations and supports	______		
Ductwork	______		
Stack	______		
Piping	______		
Insulation	______		
Painting	______		
Electrical	______		
Total installation cost	$10,000		
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land		______	
Working capital (25% of total direct operating costs)[a]		$ 9,080	
GRAND TOTAL (turnkey + land + working capital)			$ 41,080

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-100. ESTIMATED INCREMENTAL ANNUAL COSTS FOR FLUE GAS RECIRCULATION ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor	$ 1,500		
Maintenance materials			
Replacement parts			
Electricity	$22,077		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$12,741		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 36,318	
Overhead			
Payroll (30% of direct labor)	--		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,280		
Capital recovery factor (16% of total turnkey costs	$ 5,120		
Total capital charges		$ 6,400	
TOTAL ANNUALIZED COSTS			$ 42,718

---

[a] Energy usage is described in Section 5.

TABLE A-101. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)	———		
Required auxiliaries	———		
Total equipment cost	———		
Installation costs, direct			
Foundations and supports	———		
Ductwork	———		
Stack	———		
Piping	———		
Insulation	———		
Painting	———		
Electrical	———		
Total installation cost	———		
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land		———	
Working capital (25% of total direct operating costs)[a]		$ 5,500	
GRAND TOTAL (turnkey + land + working capital)			$ 37,500

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).

[b] From Annual Cost Table (see following table).

TABLE A-102. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	______		
Supervision	______		
Maintenance labor	______		
Maintenance materials	______		
Replacement parts	______		
Electricity	______		
Steam	______		
Cooling water	______		
Process water	______		
Fuel	______		
Waste disposal	______		
Chemicals	______		
Total direct cost		$ 22,000	
Overhead			
Payroll (30% of direct labor)	______		
Plant (26% of labor, parts & maint.)	______		
Total overhead cost		______	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	______		
Capital recovery factor (16% of total turnkey costs	______		
Total capital charges		$ 6,400	
TOTAL ANNUALIZED COSTS			$ 28,400

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).

TABLE A-103. ESTIMATED INCREMENTAL CAPITAL COSTS FOR STAGED COMBUSTION ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$15,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$10,000		
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land			
Working capital (25% of total direct operating costs)[a]		$ 5,592	
GRAND TOTAL (turnkey + land + working capital)			$ 37,592

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-104. ESTIMATED INCREMENTAL ANNUAL COSTS FOR STAGED COMBUSTION ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor Maintenance materials Replacement parts	$ 1,500		
Electricity - Fan	$ 9,460		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$11,407		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 22,367	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,280		
Capital recovery factor (16% of total turnkey costs	$ 5,120		
Total capital charges		$ 6,400	
TOTAL ANNUALIZED COSTS			$ 28,767

---

[a] Energy usage is described in Section 5.

TABLE A-105. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT AND FLUE GAS RECIRCULATION ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)	______		
Required auxiliaries	______		
Total equipment cost	$15,000		
Installation costs, direct			
Foundations and supports	______		
Ductwork	______		
Stack	______		
Piping	______		
Insulation	______		
Painting	______		
Electrical	______		
Total installation cost	$10,000		
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land		______	
Working capital (25% of total direct operating costs)[a]		$ 17,000	
GRAND TOTAL (turnkey + land + working capital)			$ 49,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.
[b] From Annual Cost Table (see following table)

TABLE A-106. ESTIMATED INCREMENTAL ANNUAL COSTS OF REDUCED AIR PREHEAT AND FLUE GAS RECIRCULATION ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,500		
Replacement parts			
Electricity - Fan	$22,077		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$47,636		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 71,213	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,280		
Capital recovery factor (16% of total turnkey costs	$ 5,120		
Total capital charges		$ 6,400	
TOTAL ANNUALIZED COSTS			$ 77,613

---

[a] Energy usage is described in Section 5.

TABLE A-107. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT AND LOW NO_x BURNERS ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land			
Working capital (25% of total direct operating costs)[a]		$ 6,000	
GRAND TOTAL (turnkey + land + working capital)			$ 38,000

---

[a] LNB operation is assumed to cost no more than staged combustion (see Sections 4 and 5).

[b] From Annual Cost Table (see following table).

TABLE A-108. ESTIMATED INCREMENTAL ANNUAL COSTS FOR REDUCED AIR PREHEAT AND LOW NO_x BURNERS ON A NEW 44 MW DISTILLATE OIL-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials			
Replacement parts			
Electricity - Fan			
Steam			
Cooling water			
Process water			
Fuel			
Waste disposal			
Chemicals			
Total direct cost		$ 60,000	
Overhead			
Payroll (30% of direct labor)			
Plant (26% of labor, parts & maint.)			
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)			
Capital recovery factor (16% of total turnkey costs			
Total capital charges		$ 6400	
TOTAL ANNUALIZED COSTS			$ 66,400

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).

TABLE A-109. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT OPERATION ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	0		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	0		
Total Direct Costs (equipment + installation)		0	
Installation costs, indirect			
Engineering (10% of direct costs)			
Construction and field expense (10% of direct costs)			
Construction fees (10% of direct costs)			
Start-up (2% of direct costs)			
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)			
Total Turnkey Costs (direct + indirect + contingencies		$ 2,000	
Land			
Working capital (25% of total direct operating costs)[a]		$ 7,000	
GRAND TOTAL (turnkey + land + working capital)			$ 9,000

---

[a] From Annual Cost Table (see following table).

TABLE A-110. ESTIMATED INCREMENTAL ANNUAL COSTS DUE TO REDUCED AIR PREHEAT OPERATION FOR A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	0		
Replacement parts			
Electricity	Possible small savings		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$30,495		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 30,495	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	-		
Total overhead cost		--	
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 80		
Capital recovery factor (16% of total turnkey costs	$ 320		
Total capital charges		$ 400	
TOTAL ANNUALIZED COSTS			$ 30,895

---

[a] Energy used by RAP is described in Section 5.

TABLE A-111. ESTIMATED INCREMENTAL CAPITAL COSTS FOR FLUE GAS RECIRCULATION ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$15,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$10,000		
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 8,000	
GRAND TOTAL (turnkey + land + working capital)			$ 40,000

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-112. ESTIMATED INCREMENTAL ANNUAL COSTS FOR FLUE GAS RECIRCULATION ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,500		
Replacement parts			
Electricity - Fan	$22,076		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 8,508		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 32,084	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,280		
Capital recovery factor (16% of total turnkey costs	$ 5,120		
Total capital charges		$ 6,400	
TOTAL ANNUALIZED COSTS			$ 38,484

---

[a] Energy usage is described in Section 5.

TABLE A-113. ESTIMATED INCREMENTAL CAPITAL COSTS FOR STAGED COMBUSTION ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)	—		
Required auxiliaries	—		
Total equipment cost	$15,000		
Installation costs, direct			
Foundations and supports	—		
Ductwork	—		
Stack	—		
Piping	—		
Insulation	—		
Painting	—		
Electrical	—		
Total installation cost	$10,000		
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land		—	
Working capital (25% of total direct operating costs)[b]		$ 4,500	
GRAND TOTAL (turnkey + land + working capital)			$ 36,500

---

[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-114. ESTIMATED INCREMENTAL ANNUAL COSTS FOR STAGED COMBUSTION ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,500		
Replacement parts			
Electricity - Fan	$ 9,460		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$ 7,360		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 18,320	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,280		
Capital recovery factor (16% of total turnkey costs	$ 5,120		
Total capital charges		$ 6,400	
TOTAL ANNUALIZED COSTS			$ 24,720

---

[a] Energy usage is described in Section 5.

TABLE A-115. ESTIMATED INCREMENTAL CAPITAL COSTS FOR LOW NO^x BURNERS (LNB) ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 4,000	
GRAND TOTAL (turnkey + land + working capital)			$ 36,000

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).
[b] From Annual Cost Table (see following table).

TABLE A-116. ESTIMATED INCREMENTAL ANNUAL COSTS FOR LOW NO_x BURNERS (LNB) ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials			
Replacement parts			
Electricity			
Steam			
Cooling water			
Process water			
Fuel			
Waste disposal			
Chemicals			
Total direct cost		$ 18,000	
Overhead			
Payroll (30% of direct labor)			
Plant (26% of labor, parts & maint.)			
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)			
Capital recovery factor (16% of total turnkey costs			
Total capital charges		$ 6,400	
TOTAL ANNUALIZED COSTS			$ 24,400

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[a] LNB operation is assumed to cost no more than staged combustion (see Sections 4 and 5).

TABLE A-117. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT AND STAGED COMBUSTION ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$15,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$10,000		
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 12,000	
GRAND TOTAL (turnkey + land + working capital)			$ 44,000

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[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-118. ESTIMATED INCREMENTAL ANNUAL COSTS FOR REDUCED AIR PREHEAT AND STAGED COMBUSTION ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,500		
Replacement parts			
Electricity - Fan	$ 9,460		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$38,124		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 49,084	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,280		
Capital recovery factor (16% of total turnkey costs	$ 5,120		
Total capital charges		$ 6,400	
TOTAL ANNUALIZED COSTS			$ 55,484

---

[a] Energy use is discussed in Section 5.

TABLE A-119. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT AND FLUE GAS RECIRCULATION ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost	$15,000		
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost	$10,000		
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 15,000	
GRAND TOTAL (turnkey + land + working capital)			$ 47,000

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[a] Costs are engineering estimates based on References 4-9 through 4-12, 4-14, and 4-17 through 4-20.

[b] From Annual Cost Table (see following table).

TABLE A-120. ESTIMATED INCREMENTAL ANNUAL COSTS FOR REDUCED AIR PREHEAT AND FLUE GAS RECIRCULATION ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor	0		
Supervision	0		
Maintenance labor			
Maintenance materials	$ 1,500		
Replacement parts			
Electricity - Fan	$22,076		
Steam	0		
Cooling water	0		
Process water	0		
Fuel	$39,002		
Waste disposal	0		
Chemicals	0		
Total direct cost		$ 62,578	
Overhead			
Payroll (30% of direct labor)	-		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$ 1,280		
Capital recovery factor (16% of total turnkey costs	$ 5,120		
Total capital charges		$ 6,400	
TOTAL ANNUALIZED COSTS			$ 68,978

---

[a] Energy use is discussed in Section 5.

TABLE A-121. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT AND LOW NO_x BURNERS ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$ 25,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		$ 5,000	
Total Turnkey Costs (direct + indirect + contingencies		$ 32,000	
Land			
Working capital (25% of total direct operating costs)[b]		12,000	
GRAND TOTAL (turnkey + land + working capital)			44,000

---

[a] LNB is assumed to cost no more than staged combustion (see Sections 4 and 5).
[b] From Annual Cost Table (see following table).

TABLE A-122. ESTIMATED INCREMENTAL ANNUAL COSTS FOR REDUCED AIR PREHEAT (RAP) AND LOW NO_x BURNERS (LNB) ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials			
Replacement parts			
Electricity - Fan			
Steam			
Cooling water			
Process water			
Fuel	$30,495 RAP		
Waste disposal			
Chemicals			
Total direct cost		$ 49,000	
Overhead			
Payroll (30% of direct labor)	Included above		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	$		
Capital recovery factor (16% of total turnkey costs	$		
Total capital charges		$ 6,400	
TOTAL ANNUALIZED COSTS			$ 55,400

---

[a] LNB is assumed to cost no more than staged combustion and RAP energy use is described in Section 5.

TABLE A-123. ESTIMATED INCREMENTAL CAPITAL COSTS FOR REDUCED AIR PREHEAT AND NH_3 INJECTION FOR A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Equipment cost			
Basic equipment (includes freight)			
Required auxiliaries			
Total equipment cost			
Installation costs, direct			
Foundations and supports			
Ductwork			
Stack			
Piping			
Insulation			
Painting			
Electrical			
Total installation cost			
Total Direct Costs (equipment + installation)		$180,000	
Installation costs, indirect			
Engineering (10% of direct costs)	Included above		
Construction and field expense (10% of direct costs)	Included above		
Construction fees (10% of direct costs)	Included above		
Start-up (2% of direct costs)	Included above		
Performance tests (minimum $2000)	$ 2,000		
Total Indirect Costs		$ 2,000	
Contingencies (20% of direct and indirect costs)		Included above	
Total Turnkey Costs (direct + indirect + contingencies		$182,000	
Land			
Working capital (25% of total direct operating costs)[b]		$ 13,000	
GRAND TOTAL (turnkey + land + working capital)			$195,000

---

[a] NH_3 injection costs are extrapolated from utility boiler data (References 4-4 and 4-5).

[b] From Annual Cost Table (see following table).

TABLE A-124. ESTIMATED INCREMENTAL ANNUAL COSTS FOR REDUCED AIR PREHEAT (RAP) AND NH_3 INJECTION ON A NEW 44 MW NATURAL GAS-FIRED WATERTUBE BOILER WITH AN AIR PREHEATER[a]

Direct cost			
Direct labor			
Supervision			
Maintenance labor			
Maintenance materials	\$24,000 NH_3 injection (all direct costs)		
Replacement parts			
Electricity - Fan			
Steam			
Cooling water			
Process water			
Fuel	\$30,495 RAP		
Waste disposal			
Chemicals			
Total direct cost		\$ 54,495	
Overhead			
Payroll (30% of direct labor)	Included above		
Plant (26% of labor, parts & maint.)	Included above		
Total overhead cost			
By-product credits		( )	
Capital charges			
G & A, taxes and insurance (4% of total turnkey costs)	\$ 7,280		
Capital recovery factor (16% of total turnkey costs	\$29,120		
Total capital charges		\$ 36,400	
TOTAL ANNUALIZED COSTS			\$ 90,895

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[a] Ammonia injection costs are extrapolated from utility boiler data (References 4-4 and 4-5) and RAP energy use is from Section 5.

APPENDIX B

LIST OF COMMON ABREVIATIONS

BOOS	Burners out of service
CO	Carbon monoxide
EPA	Environmental Protection Agency
FGR	Flue gas recirculation
HC	Hydrocarbon
LEA	Low excess air
LNB	Low NO_x burner
LR	Load reduction
N_2	Nitrogen
NH_3	Ammonia
NO_x	Nitrogen oxides
O_2	Oxygen
OFA	Overfire air
PAH (PNA)	Polynuclear aromatic hydrocarbon
POM	Polycyclic organic matter
RAP	Reduced air preheat
SCA	Staged combustion air
SFA	Sidefire air
SIP	State implementation plan
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
UHC	Unburned hydrocarbon

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